

Analysis of Resource Adequacy across the Eastern Interconnection

An open-source case study using GridPath

Study Slidedeck

July 2025

See gridlab.org/GridPath_EI for report and other materials

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TELOS
ENERGY



Agenda

- 01** Introduction
- 02** Methodology
- 03** Inputs & Assumptions
- 04** Results
- 05** Key Findings and Next Steps



Disclaimer and Study Limitations

**Local vs.
Wide Area
Assessments**

This report analyzes the benefits of wide-area resource adequacy assessments and was performed on the entire Eastern Interconnect. It is not intended to duplicate or replace individual ISO or utility plans or analysis. As a result, findings may deviate from ISO or utility analysis.

**Forward
Projections**

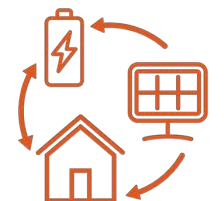
This analysis evaluates resource adequacy in 2028. It includes load growth, announced retirements and new resources that are under construction. It quantifies resource needs, but such findings do not imply regions will be unreliable since additional resources, transmission or demand side approaches can potentially mitigate reliability risk.

**Weather
Dependent
Outage Risk**

This study does not currently include correlated, weather dependent outage risk of thermal generation, including but not limited to natural gas availability or cold-weather related equipment outages. That assumption would generally lead to estimates of lower winter risk, than if temperature-dependent outages were included. This is identified for future research.

**Canadian
Regions**

Canadian regions were not explicitly modeled as additional zones in this analysis due to lack of consistent, publicly available data. However, as a proxy, interchange between Canada in the U.S. (as well as the Western Interconnection) is modeled through a representation of imports based on historical flows.



Introduction

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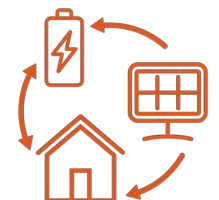
Study Overview

Wide Area Resource Adequacy Study of the Eastern Interconnection

Objectives

1. Conduct a resource adequacy analysis of the Eastern Interconnection to calculate near-term (2028) loss of load risk of the system.
2. Evaluate the role of interregional transmission and market assistance on resource adequacy by evaluating regions with varying amounts of interregional transmission capability.
3. Develop a publicly available dataset and model using the GridPath open-source model that can be used by researchers and industry for future studies.

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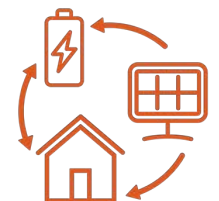


Why perform wide-area assessments?

- **Interregional Transmission Planning:** identify transfer limitations and uncover high-value opportunities for new interregional transmission.
- **Scenario Consistency:** shared scenarios and assumptions that improve alignment across planning entities.
- **Neighboring System Visibility:** Resource mix and load changes in adjacent regions can significantly affect local adequacy. A wide area view helps planners anticipate these shifts and plan accordingly
- **External Assistance Evaluation:** assessing regional capacity needs both with and without imports clarifies the extent to which reliability depends on neighboring systems.
- **Extreme weather event evaluation:** help identify strategies for managing risks posed by large-scale weather events that span large geographies, like polar vortexes or heat domes.
- **Methodological and metric alignment:** developing shared input data, modeling approaches, and common metrics increases transparency and comparability across regions.

Source: Energy Systems Integration Group, Best Practices for Wide Area Assessments
(Report forthcoming; fact sheet available at esig.energy)

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GridPath RA Toolkit

Open-Source Modeling for Power System Planners, Researchers, and Industry

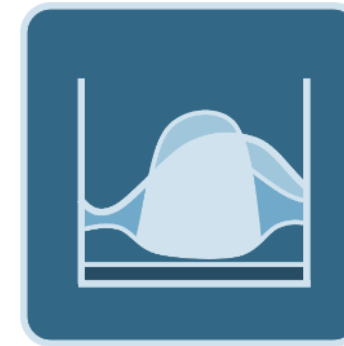
- **GridPath**, open-source power system platform developed and maintained by Sylvan Energy Analytics, which includes capacity expansion, production cost, and RA modeling:
<https://github.com/blue-marble/gridpath>
- **Western US Dataset** which includes the load, resource, and transmission data for conducting RA assessments of the Western US in 2028:
www.gridlab.org/GridPathRAToolkit
- **Eastern US Dataset** which includes models and data used to conduct this study.
www.gridlab.org/GridPath_EI

Users can customize the datasets to evaluate other systems, years, or portfolios. Users can also modify the code to create new functionality in GridPath.



Capacity Expansion

- Fully customizable temporal granularity, geo-spatial granularity, and sampling methodology
- Endogenous retirements, transmission expansion, and DSM selection
- Stochastic optimization for planning under uncertainty*
- Automated integration with resource adequacy and production cost modeling via iterative optimization*



Production Cost

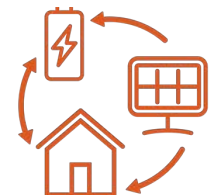
- Multi-stage scheduling, commitment, and dispatch optimization
- Fully customizable temporal and geo-spatial granularity
- Zonal, nodal pipe flow, and DC power flow transmission options
- Market energy and ancillary service* price-responsive dispatch



Resource Adequacy

- Time-sequential and energy-constrained dispatch simulation
- Zonal transmission constraints and path limits
- Synchronized or Monte Carlo weather treatment for loads and resource availability over wide areas
- Weather-driven Monte Carlo outages

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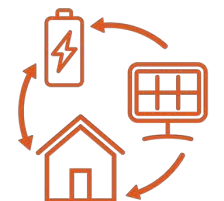
GridPath RA Toolkit

Key features for RA analysis

- **Weather correlations**
Evaluated weather-synchronized wind, solar, and load data to capture key weather correlations over very large geographical areas
- **Energy-limited resources**
Dynamic dispatch of energy-limited resources, like hydropower, energy storage, and demand response to avoid lost load
- **Transmission and regional coordination**
Dynamic transmission flow modeling provides transparency into weather-coherent and transmission-constrained market availability.



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Methodology

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Methodology

Perform sequential, Monte-Carlo, probabilistic production cost simulations across multiple weather years, to calculate loss of load probability



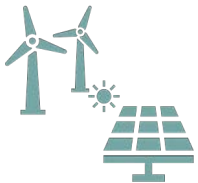
Sequential: annual, 8760 hour-by-hour dispatch of the system, including changes in load, wind and solar variability, time varying generator outages, and storage scheduling



Monte Carlo: repeated random sampling of individual, generator outages using outage rates and repair time distributions

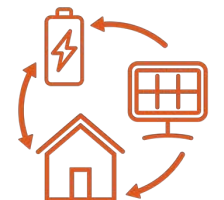


Generator Dispatch: A simplified generator dispatch based hourly availability with increasing cost of generation at tight reserves, allowing for scheduling of battery storage and interregional transmission flows.



Weather-synchronized: 12-years of hourly data was used for load, wind, solar, and temperature to preserve correlation in resource availability and demand, combining both modeled weather and actual observations

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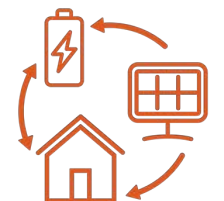
Evaluating chronological system operations across multiple weather years



Increase in variable renewable energy and energy limited resources requires resource adequacy to consider *chronology* and *correlation*

- Hundreds of hourly dispatch simulations, considering generating characteristics, hourly changes in load and renewable output, forced outages (randomly occurring)
- Storage scheduling and transmission flows is based on arbitraging energy margins temporally and spatially, but high value of lost load (VoLL) ensures sufficient state of charge is available during scarcity events
- No hydro sampling was performed across various weather years due to relatively low hydro resources in the Eastern Interconnect

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How Weather Affects Resource Adequacy

Load Variability



- Loads are highly dependent on the temperature and other ambient conditions
- Extreme cold and heat will drive peak loads and resource adequacy risk

Renewable Variability



- Seasonal and hourly variability causes renewables availability to fluctuate
- In a high renewable system, wind and solar availability can significantly impact RA risk

Generator Outages

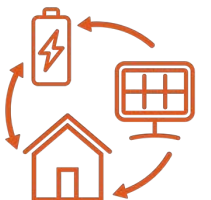


- Likelihood of generators being on outage due to planned or forced maintenance
- Also affected by the weather, but often not reflected in resource adequacy analysis

← **Need to consider *correlated* risks across the three drivers** →

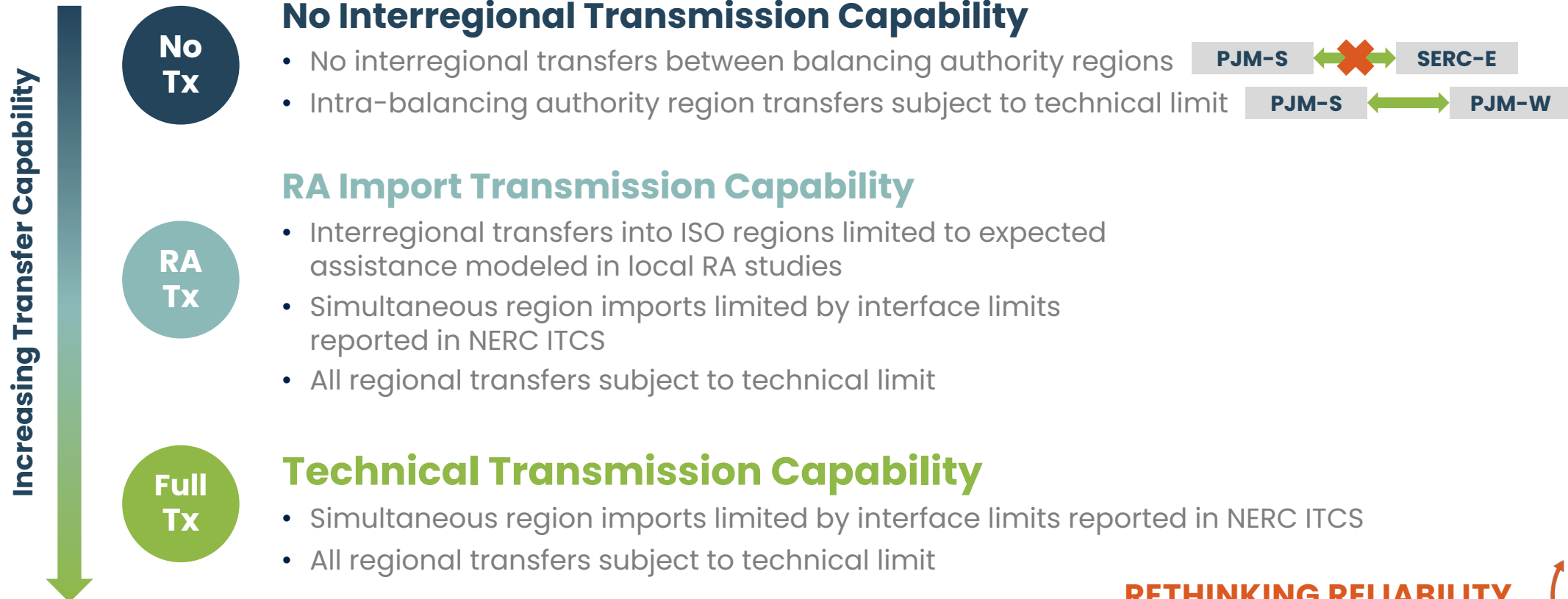
Currently, our analysis considers weather correlations with load and renewable generation. Thermal outages will be included in future analysis.

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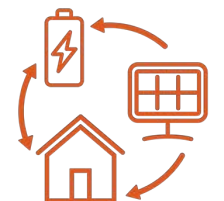


Study Scenarios

Three transmission scenarios were conducted to evaluate benefits of interregional transmission



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Inputs & Assumptions

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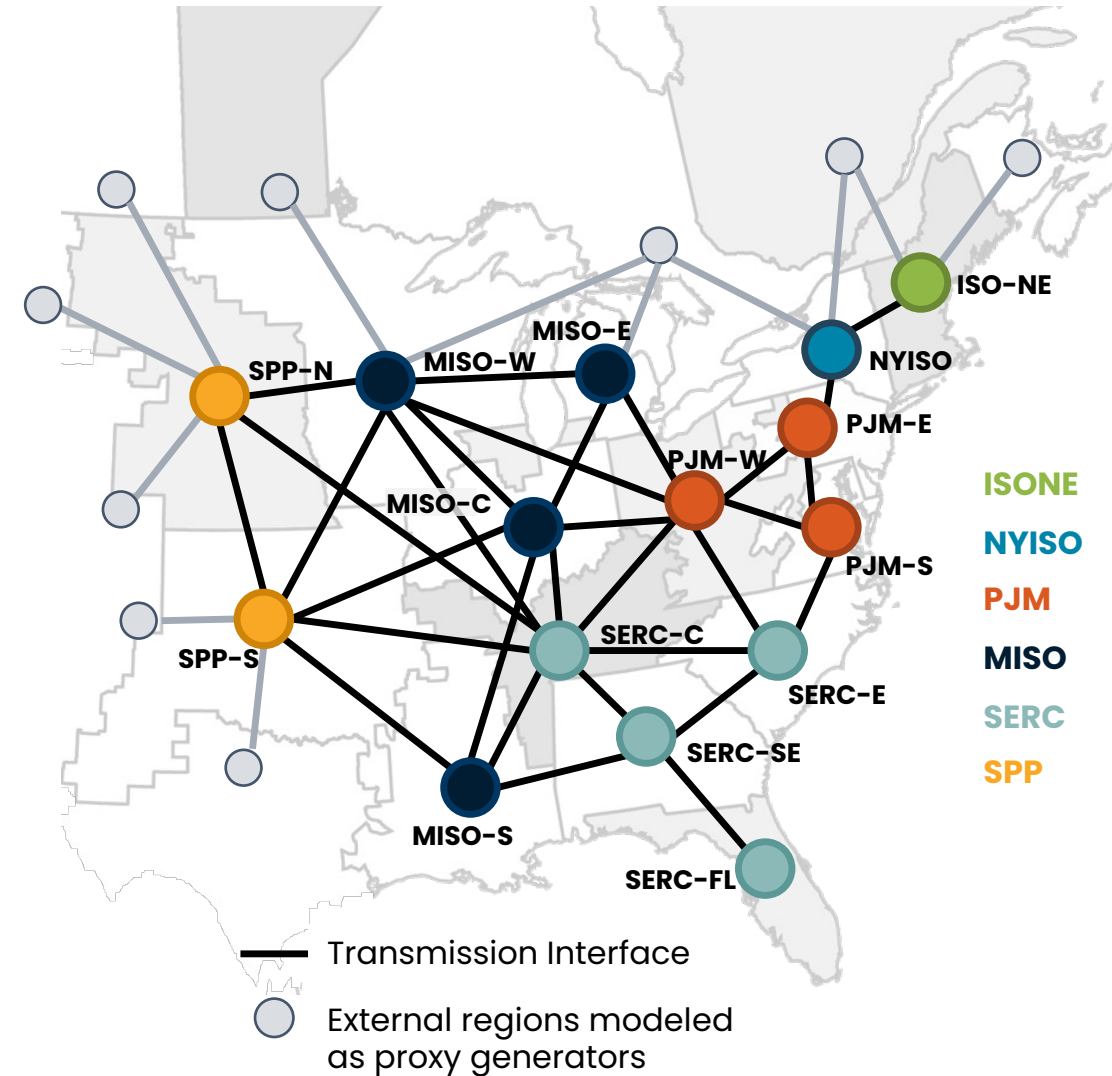


Table of Key Assumptions

		Data Source
Transmission Topology	Transmission planning regions, region-to-region transfers, and regional total import capabilities from the NERC Interregional Transfer Capability Study. Adjustments for scenarios based on ISO studies and NERC LTRA.	ISO RA Studies & NERC ITCS
Generator Capacities	Existing and under construction capacity expected online by 2028 and announced retirements, aggregated by transmission planning region and fuel type	EIA Form 860
Peak Demand Forecast	Latest ISO forecasts where applicable, and the 2024 NERC Long-Term Reliability Assessment for non-ISO regions. Forecast year 2028.	ISO Demand forecasts & NERC 2024 LTRA
Load Profiles	NREL Standard Scenarios Load Forecasts for Weather Year 2007–2013 developed by Evolved Energy Research. Adjusted actual demand for Weather Year 2019–2023 based on EIA 930 reported data.	NREL Standard Scenarios & EIA 930
Hourly Wind Profiles	Aggregated NREL Wind Toolkit data for Weather Years 2007–2013, including bias correction, siting based on NREL ReEDS model. Weather Years 2019–2023 based on actual wind generation reported in EIA 930.	NREL Standard Scenarios & EIA 930
Hourly Solar Profiles	Aggregated NREL NSRDB data for Weather Years 2007–2013, including bias correction, siting based on NREL ReEDS model. Weather Years 2019–2023 based on actual solar generation reported in EIA 930.	NREL Standard Scenarios & EIA 930
Forced Outage Rates	Unit-level outage rates derived from NERC GADS class average forced outage rates, aggregated by transmission planning region and fuel type	NERC GADS Brochure

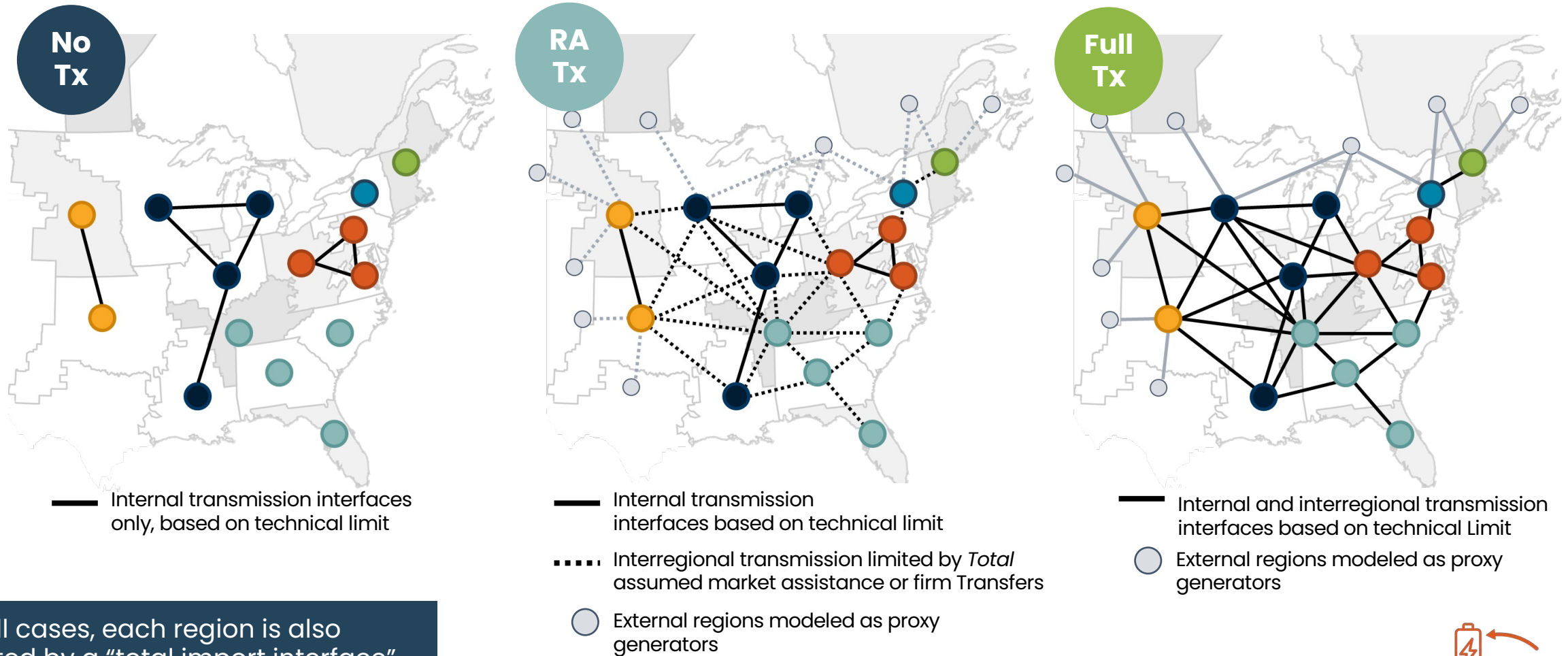
Study Topology

- Eastern Interconnect divided into Transmission planning regions aligned with NERC ITCS topology.
 - SPP, MISO, and PJM are divided into sub-regions
 - SERC regions divided into NERC Assessment Areas
- Flows across transmission interfaces limited to region-to-region technical transfer capability
- Simultaneous flows into all regions are modeled with a simultaneous import capability
 - Sub-region to sub-region flows not affected
- External interties in WECC and Canada are modeled as proxy generators with a max rating and daily energy budget



Regions are assumed to serve their own load first, imports/exports are for reliability purposes only, after exhausting local resources

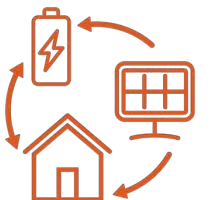
Transmission Scenarios



In all cases, each region is also limited by a "total import interface" in addition to limits on individual interfaces.

Assumed limit on assumed market assistance based on ISO studies or firm imports in the NERC LTRA.

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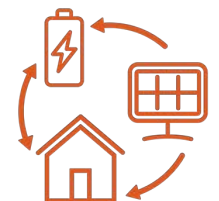


Transmission Detailed Assumptions

The transmission topology is composed of three different assumptions:

- 1. Region-to-Region Transfer Interface Capability:**¹ each region-to-region interface transfer capability is modeled based on the results of the NERC Interregional Transfer Capability Study (Part 1) and includes an analysis of AC power flow under N-1 contingencies. It reflects the maximum amount of transfer from one region to a neighboring region. However, the transfer capability between two regions is affected by the network topology of other neighboring systems. As a result, it is a non-coincident transfer capability, as it cannot be assumed that all of a region's importing interfaces can reach their technical limit at the same time. These limits are unchanged across all scenarios; however interregional transfers are not permitted in the No Tx scenario.
- 2. Total Simultaneous Import Capability:**¹ To reflect the coincident import capability across all importing interfaces, each region is also modeled with maximum total import capability that limits the simultaneous imports across all region-to-region interfaces going into a region. This is also a technical limit based on the results of the NERC Interregional Transfer Capability Study (Part 1). This is included for all regions and is consistent across all scenarios.
- 3. RA Import Limit:** In addition to the technical limits applied in #1 and #2, the RA import limit is an additional constraint that limits flows based on ISO assumptions or firm contracts. This is not a technical limit but rather an assumed limit on market assistance from neighbors. For ISOs with multiple sub-regions (SPP, MISO, PJM) the RA Import Limit is set for the entire ISO footprint. The RA Import Limit is assumed only in the RA Tx Scenario.

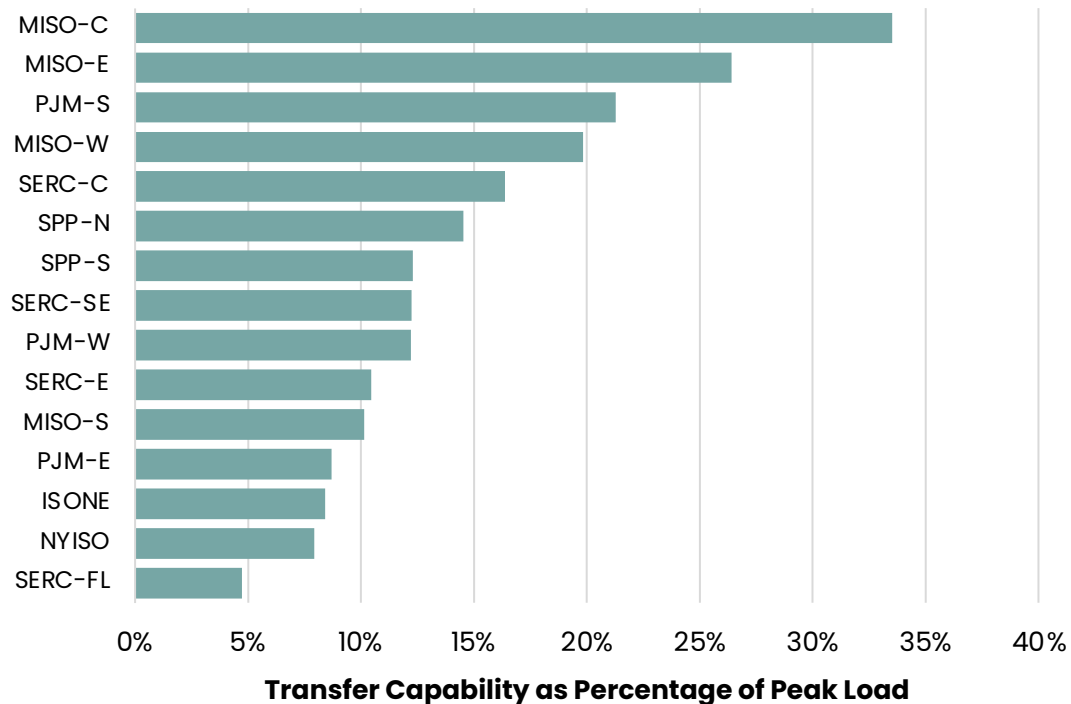
¹**Data Source:** North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study (ITCS), Transfer Capability Analysis (Part 1)*, August 2024, https://www.nerc.com/pa/RAPA/Documents/ITCS_Part_1_Results.pdf.



Interregional Transfer Interface Limits

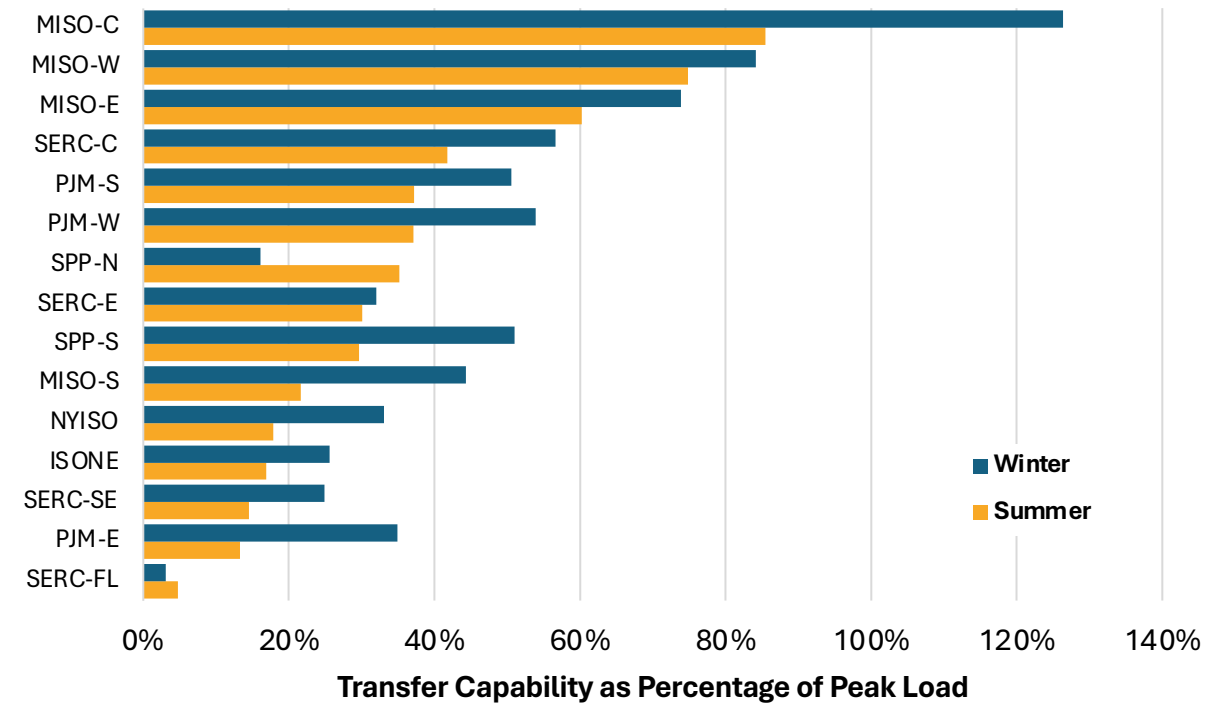
Coincident Transfer Capability

(simultaneous import capability)

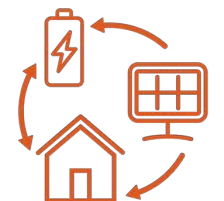


Non-Coincident Transfer Capability

(sum of individual ties)



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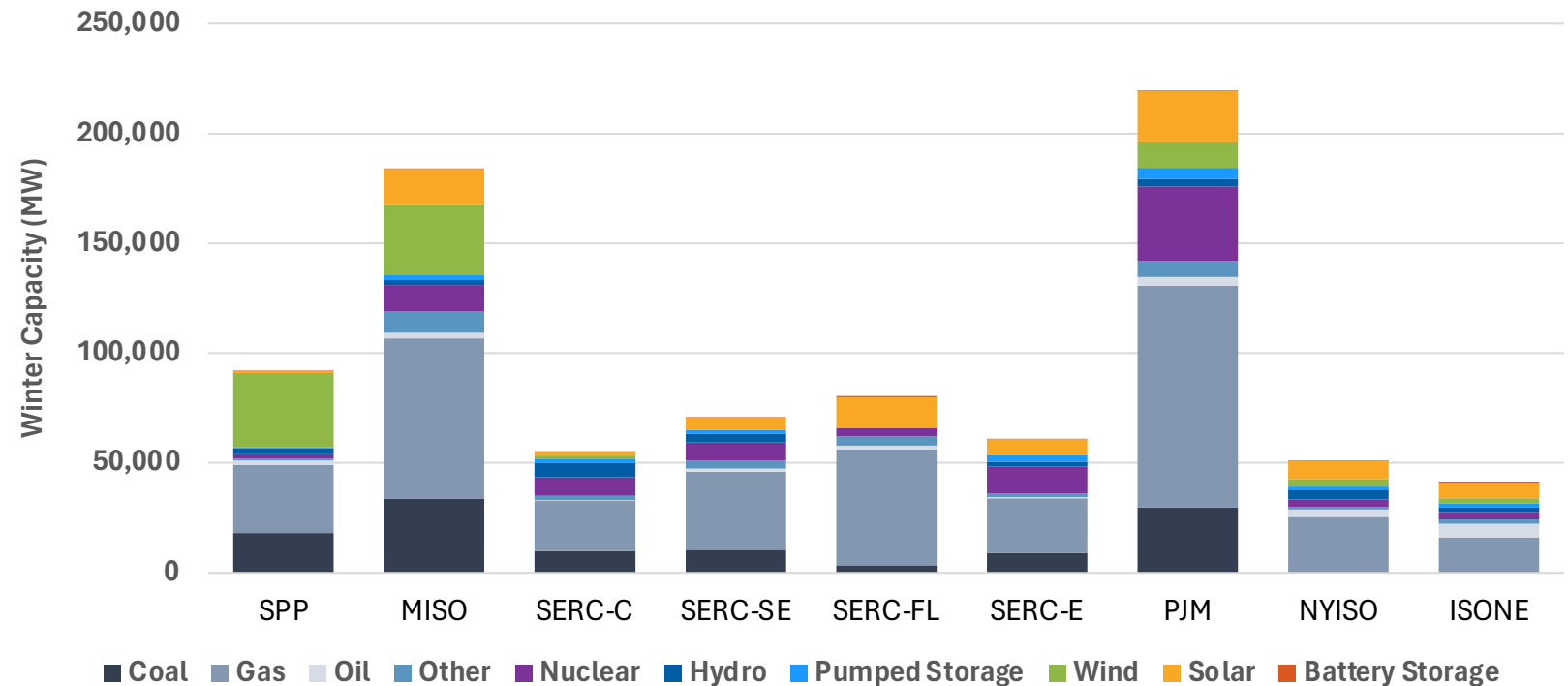


Generator Capacities by Resource Type

- Gathered from “Operable” and “Proposed” generators in EIA 860 2024 Data Forms
- Accounted for retirements and new installations as of January 2028.
- New installations only include projects under construction or with regulatory approval in the EIA 860 2024 Data Forms
- Mapped to transmission planning regions based on state, balancing authority, or manual mapping where needed.

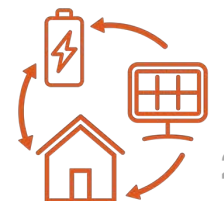
Data Source: EIA-860

2028 Capacity by Region, by Resource Type (MW)



Note: Chart shows winter capacity for thermal resources, nameplate for wind, solar, hydro, and storage

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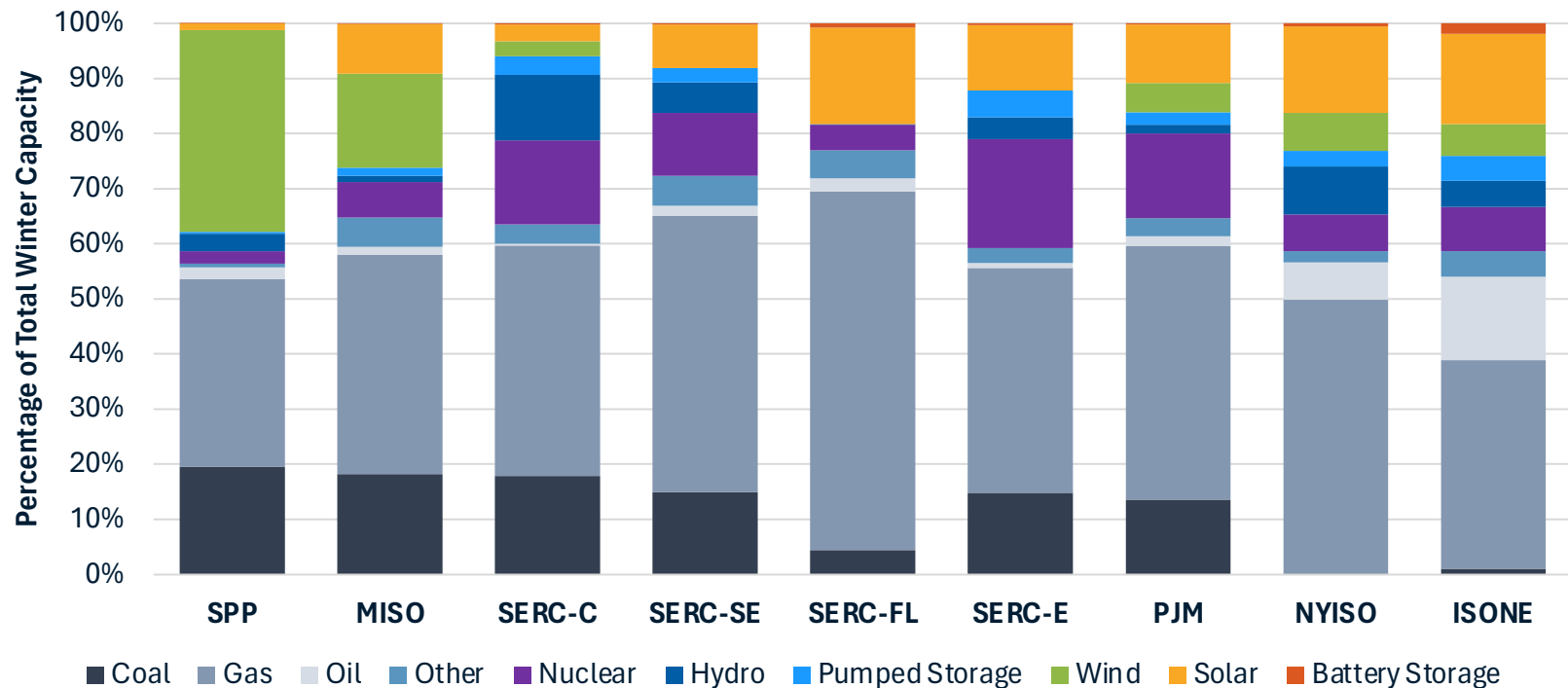


Generator Capacities *(continued)*

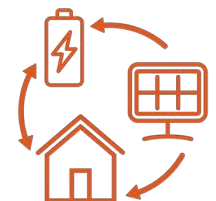
- Gathered from Operable and Proposed generators in EIA 860 2024 Data Forms
- Accounted for retirements and new installation as of 2028.
- New installations only include projects under construction or with regulatory approval
- Mapped to transmission planning regions based on state, balancing authority, or manual mapping where needed.

Data Source: EIA-860

2028 Capacity by Region, by Resource Type (% of Total)

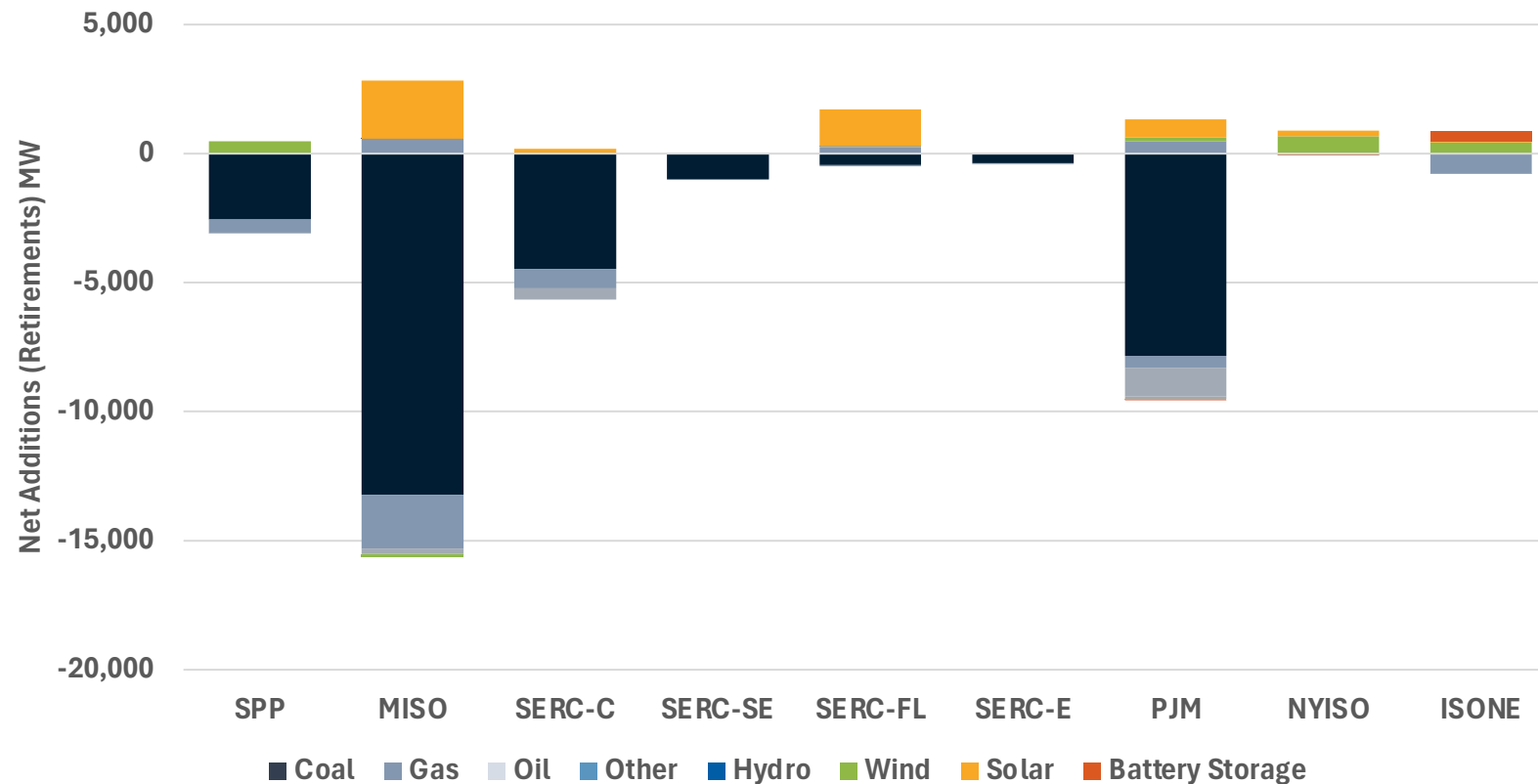


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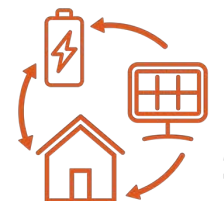
Installations and Retirements

Net Generation Additions (+) and Retirements (-) from 2024 to 2028



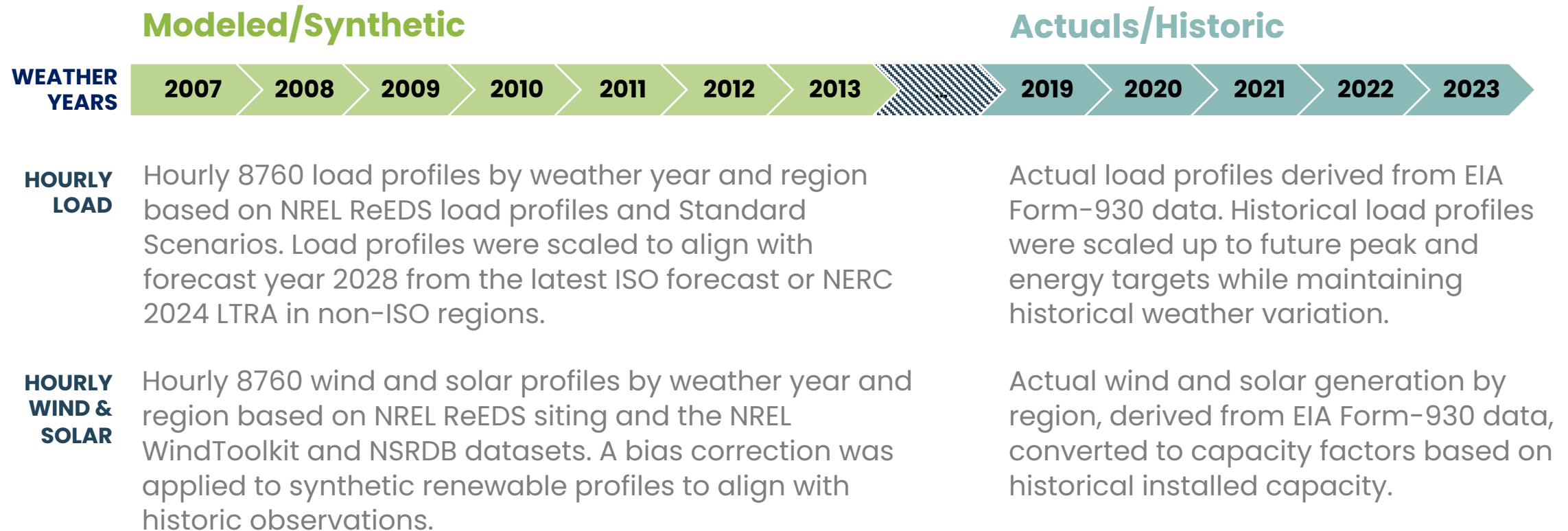
- New installations predominately from wind, solar, and storage resources
- Limited new gas build, even in regions with significant retirements
- 30 GW of coal retirements, primarily in SPP (2.6 GW), MISO (13.4 GW), SERC-C (4.5 GW) and PJM (7.8 GW)
- The model is based on announced retirements and late-stage resource additions. No requirement for equal replacement

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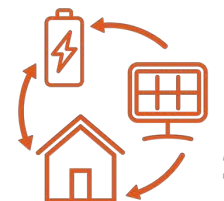
Weather Years

Approach leveraged both synthetic, modeled datasets and actual historic observed profiles.



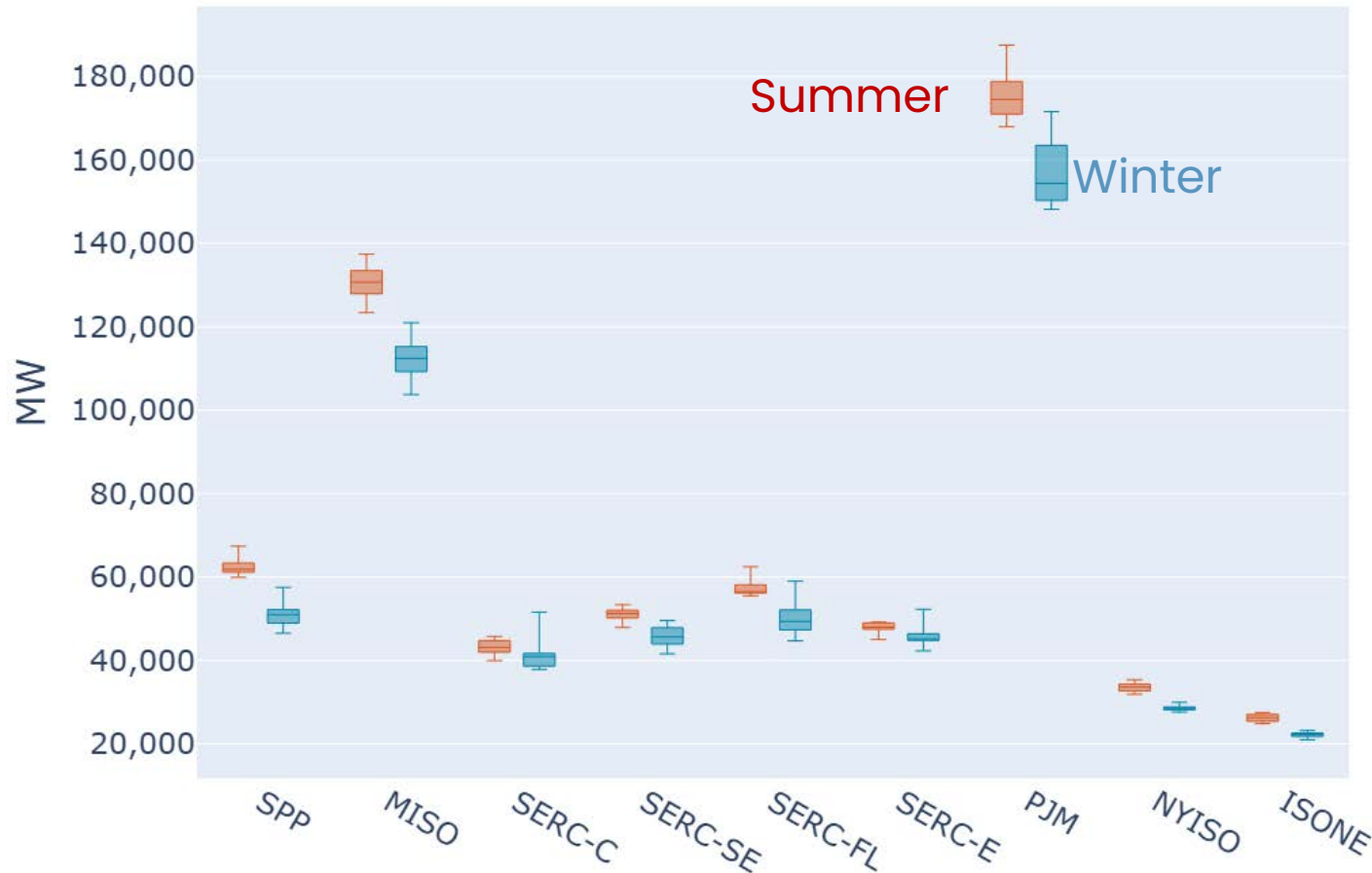
This study assumed physically consistent weather to maintain weather correlation and consistency and did not introduce Monte Carlo sampling

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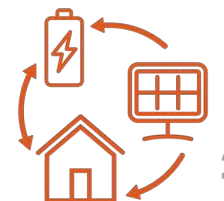
Peak Load Across All Weather Years

Seasonal Peak Demand (MW) Summer and Winter



- Latest ISO forecasts for seasonal peak demand and NERC 2024 LTRA for non-ISO regions.
- **Most recent forecasts include substantial new data center demand**
- Range of seasonal peak demands vary due to weather conditions observed during 2007-2013 and 2019-2023 historical weather years
- All regions in the EI are summer peaking under normal weather years, but some region are dual peaking during cold (SERC-C, SERC-FL, SERC-E, PJM)
- Summer peak varies +/- 5%
- Winter peaks can vary by +/- 10 to 15%

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Load Scaling Methodology

Synthetic Load Data (2007–2013)

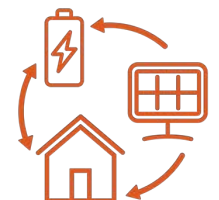
- Beginning with Evolved Energy Research Baseline AEO 2022 hourly load scenario, gross load profiles were aggregated from ReEDs region into GridPath regions
- Median annual energy and summer/winter peak loads were compared to the P50 LTRA forecast
- Hourly synthetic load scaled to align median annual energy with the 2028 ISO or LTRA forecast
- Median seasonal peak loads aligned between synthetic data and LTRA forecast without changing annual energy.

Historical Load Data (2019–2023)

- Beginning with EIA 930 load data, load profiles were cleaned and aggregated from BA-level data into GridPath regions
- Energy added to each hour in a Weather Year to meet LTRA Forecast values
- Then, energy-shifted profile multiplied by constant seasonal scalar aligned with median seasonal peak between 2019–2023 in the LTRA forecast
- Repeat energy shift and seasonal scaling until shift is less than 50 MW for each hour

For all weather years, final load profiles scaled up or down to have median annual peak load meet 2028 forecasted peak load sourced from ISO studies or NERC LTRA.

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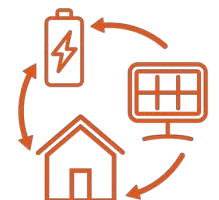
Renewable Profile Methodology

Synthetic Renewable Profiles (2007–2013)

- NREL NSRDB and WindToolkit data sources provided simulated renewable generation profiles based on resource class (quality) and resource type.
- Locations of existing and future wind and solar projects based on siting in the NREL ReEDS model.
- The generation profiles and installed capacity values created a capacity-weighted production profile for each GridPath region.

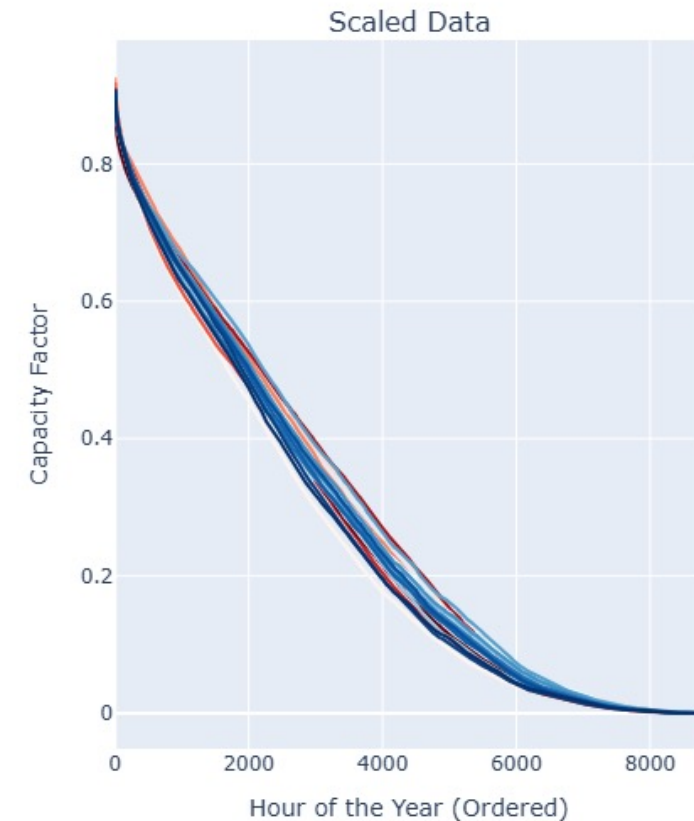
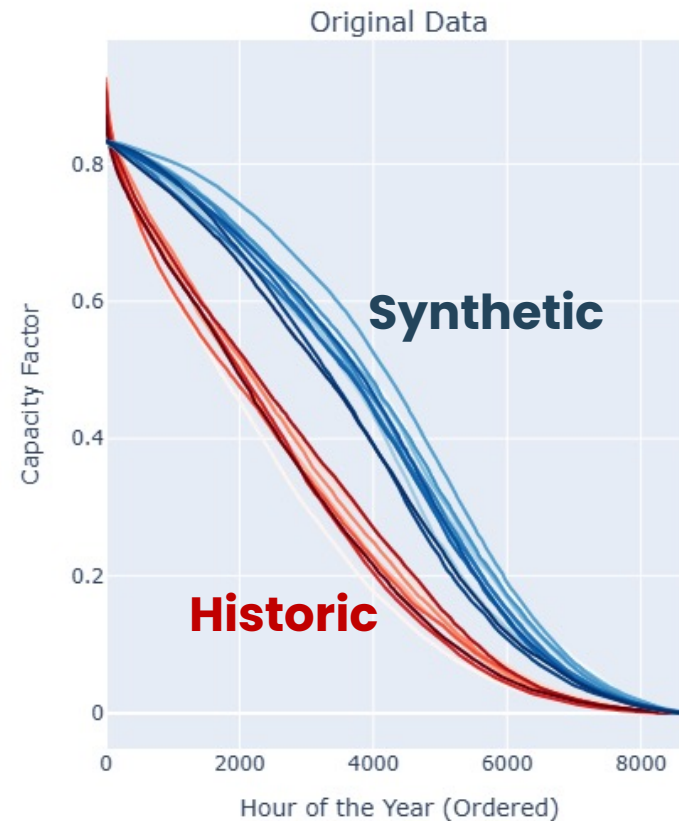
Historical Renewable Profiles (2019–2023)

- EIA 930 data provided hourly renewable generation profiles at the BA level
- EIA 860M data provided renewable capacity by type at the BA level
- BA level capacity factors were calculated and aggregated up to GridPath regions on a capacity-weighted basis.

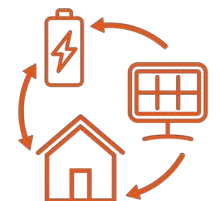


Renewable Profile Bias Adjustment

- To remove the observation bias in the NREL data, we scale the hourly, rank-ordered capacity factors so that for every hour of the rank-ordered data, the median capacity factor from the NREL data matches the median from the actual data.
- Hourly scalar instead of annual scalar preserves tail-end output
- Regional scalars preserves chronology of wind and solar profiles, differences in technology types, curtailment trends, etc.



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Forced Outage Sampling Method

Chronological forced outage modeling  **Random sampling 900x per day, N = 328,500**

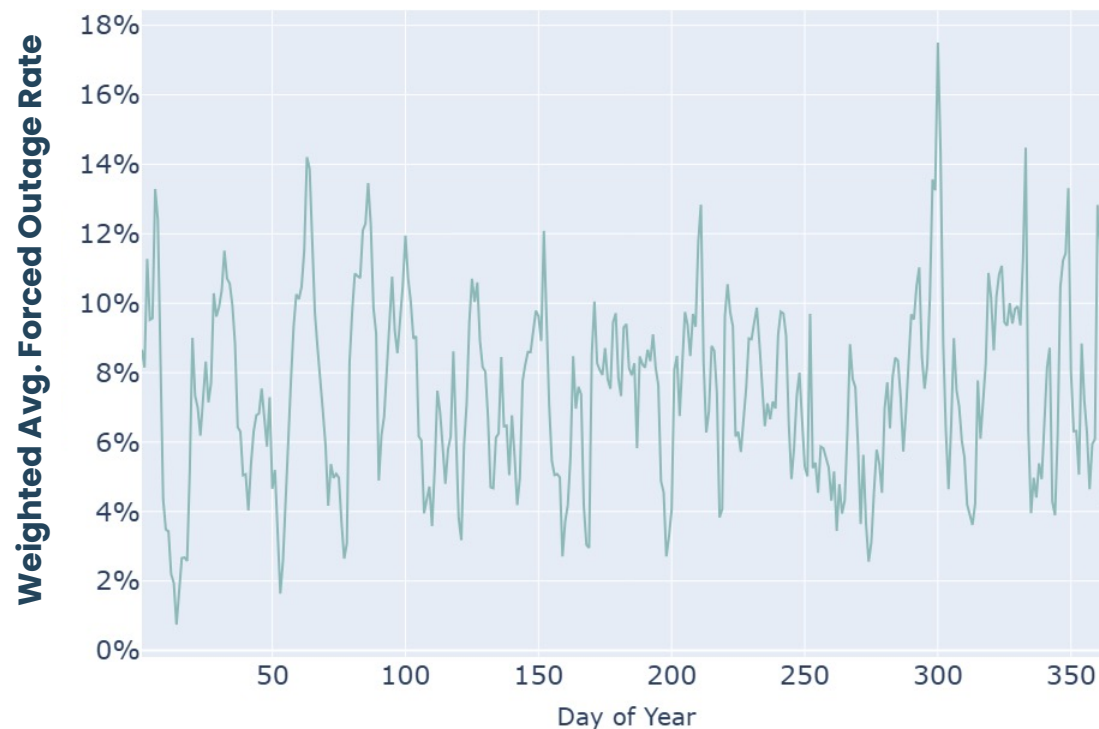


Illustration for MISO-E natural gas capacity on outage for a single sample (left) and across 900 samples (right).

Each individual generator was assigned a forced outage factor, based on GADS technology type and size. Sampling was conducted exogenous to the model and aggregated by region and fuel type in GridPath. Sampling process was repeated for all resource types and assumed no correlation across resources or load levels.

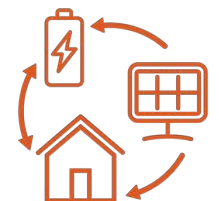
Study Inputs: “Cost” Curve

- The study utilizes a simplified cost curve to schedule resources but does not try to conduct a full production cost simulation.
- Instead, shadow costs were assumed that increased the price in a region as more available capacity was needed to serve load. This is used for three reasons:
 - 1. Schedule storage to arbitrage margin:** charge during high margin, low price hours, discharge during low margin, high price hours
 - 2. Utilize a region’s internal resources first,** prior to relying in imports for resource adequacy. This ensures loss of load shows up in the region that has insufficient local capacity rather than based on economics.
 - 3. Prioritize imports from regions with higher margin,** based on reliability, not economics.
- In the event load is not served after exhausting generation and transmission, **unserved energy** is assigned a penalty.

Category	Object	Cost (\$/MWh)
Generation	Tranche 1	\$0
Generation	Tranche 2	\$5
Generation	Tranche 3	\$10
Generation	Tranche 4	\$20
Generation	Tranche 5	\$40
Generation	Tranche 6	\$80
Generation	Tranche 7	\$160
Generation	Tranche 8	\$320
Load	Demand Response	\$640
Transmission	Import Hurdle Rate	\$1,000
Load	Unserved Energy Penalty	\$20,000

Battery and Pumped Storage not included in Cost Curve to allow storage of energy from low-cost to high-cost periods.

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Detailed Assumptions

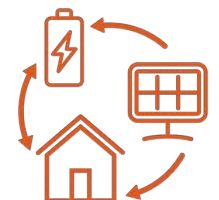
Generator Additions	Assumed only projects in advanced stages of development, including testing, commissioning. The EIA Status codes applied for generator additions were "U", "V", and "TS".
Seasonal Capacity	Utilized summer and winter capacities based on Form EIA-860. No additional ambient derates were applied.
Operating Reserves	Assumed all regions carried reserves equal to the largest contingency relative to peak load. For example, a region with 20,000 MW peak load and largest generator of 1,000 MW is assigned reserve percentage of 5% across all hours. Load is shed prior to violating this reserve. SPP, MISO, and PJM reserves are set at the balancing authority level (i.e. PJM) and not at the sub-regional level (i.e. PJM-S, PJM-E, PJM-W)
External Regions	Canadian regions and interties to the Western Interconnection were modeled as a proxy generator based on historical flows. The seasonal rating was set to the 99 th percentile of observed flows. Daily energy budgets were set based on five years of historical daily net interchange, in MWh (EIA-930) and randomly sampled by day. Future improvements will expand sampling by month.
Interchange rules	Each region was assumed to serve its own load prior to imports and exports, holding interchange between regions as a resource of last resort. This was done by setting the cost of import/export higher than the cost of all types of native generation.
Battery Storage	Battery storage is scheduled to arbitrage across price, which is set as a function of the relative hourly energy margin in the region. When combined with a value of lost load (VoLL) the battery storage will also be scheduled to minimize loss of load.
Energy limitations	Energy limited resources (hydro, proxy imports, and demand response) were scheduled with daily energy budgets and hourly minimum and maximum flows.
Objective Function	In this use case GridPath will minimize total cost, where cost is an assumed shadow cost that increases as total reserves on the system become tighter. When combined with a high value of lost load (VoLL) the optimization will also minimize costs incurred from unserved energy.

Limitations and Future Development

Additional refinements to data, scheduled for future release, will improve the following:

- **Weather dependent outages** for thermal resources to capture temperature correlations between load and outages
- **Inclusion of planned outages** and maintenance rates will decrease capacity availability slightly during peak conditions, but may introduce risk during shoulder seasons
- **Additional weather years** of correlated wind, solar, and load data will span 2007–2024 period.
- **Canadian regions** had insufficient publicly available data and were modeled as a proxy generator with seasonal ratings and daily energy budgets based on observed historical flows. Future development will include a full representation of the regions.

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Results

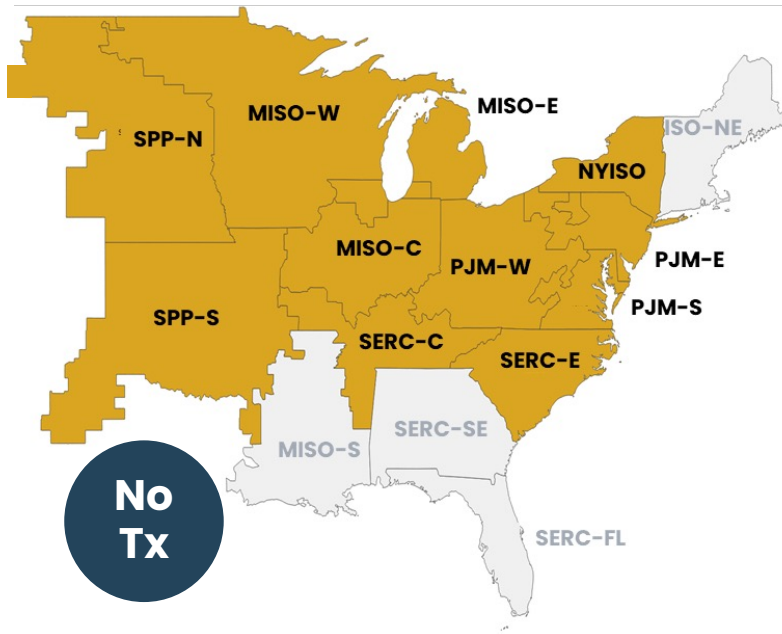
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Eastern Interconnect Risk Map

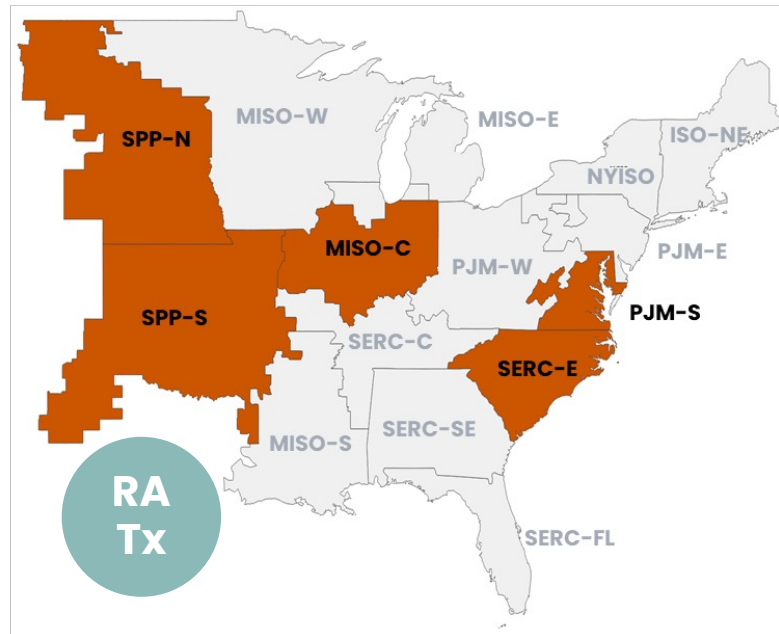
Moderate Risk

Greater than 0.1 days/year LOLE, but only without interregional transfers



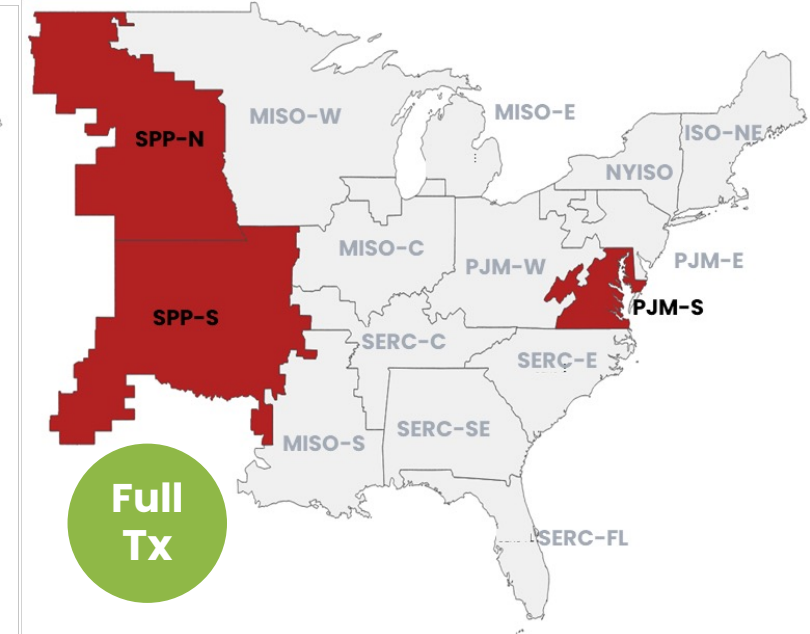
Elevated Risk

Greater than 0.1 days/year LOLE when using a region's RA import levels



High Risk

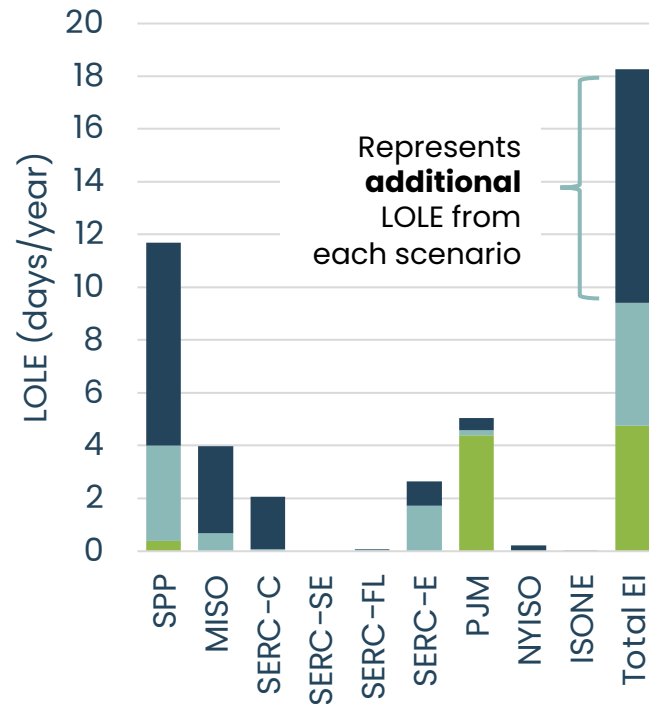
Greater than 0.1 days/year LOLE in all scenarios, even with full transfer capability



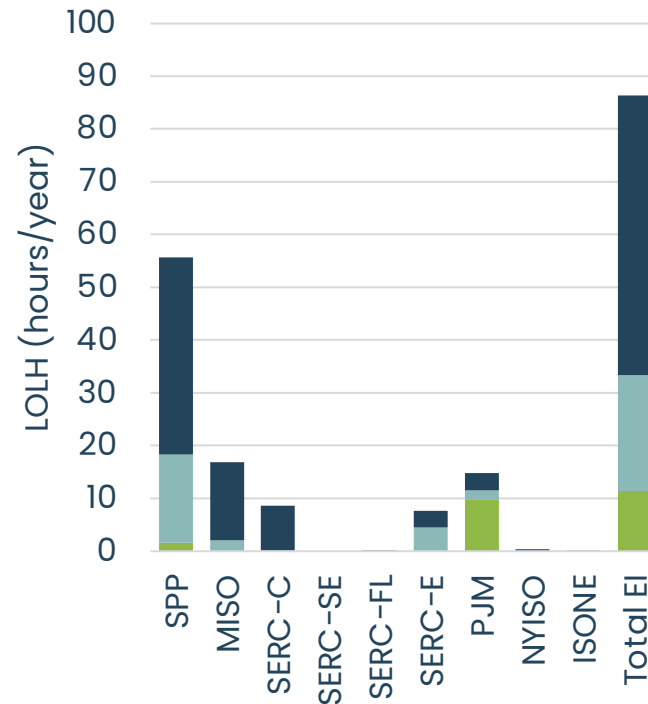
RA Summary Statistics

by Region and Scenario

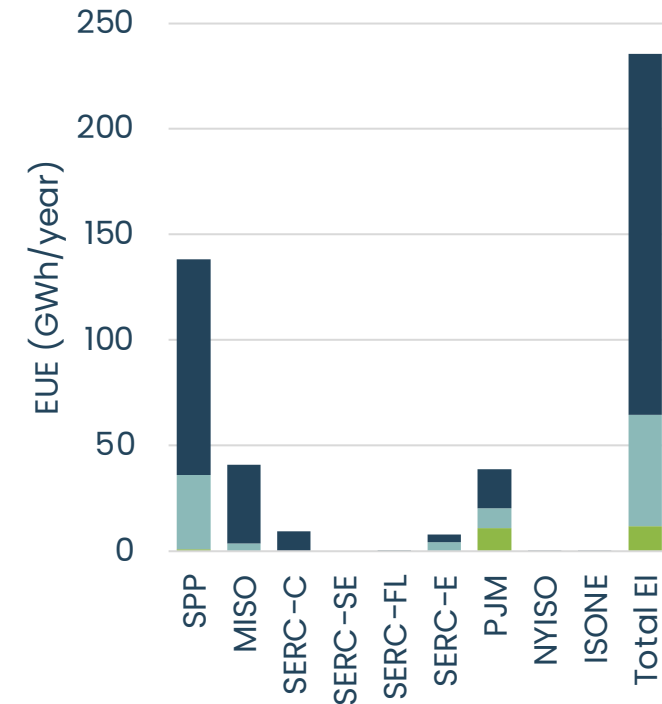
Loss of Load Expectation



Loss of Load Hours

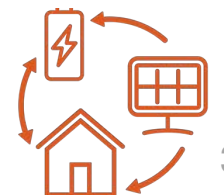


Expected Unserved Energy



■ No Tx (+ RA Tx + Full Tx) ■ RA Tx (+ Full Tx) ■ Full Tx

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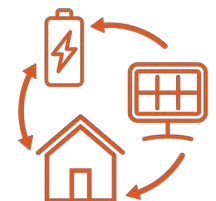
Detailed Results, RA Tx

RA Tx	LOLE days/yr	LOLH hrs/yr	EUE MWh/yr	NEUE % of load
Total EI	9.40	33.39	64,642	0.0018%
SPP	4.00	18.38	36,060	0.0108%
SPP-N	3.18	12.56	9,162	0.0111%
SPP-S	3.61	15.59	26,899	0.0107%
MISO	0.67	2.09	3,547	0.0005%
MISO-W	0.07	0.16	155	0.0001%
MISO-C	0.67	2.06	3,245	0.0016%
MISO-E	0.05	0.19	101	0.0001%
MISO-S	0.03	0.09	45	<0.0001%
SERC-C	0.08	0.19	155	0.0001%
SERC-E	1.73	4.49	4,381	0.0018%
SERC-FL	0.06	0.07	39	<0.0001%
SERC-SE	0	0	0	0.0000%
PJM	4.58	11.49	20,460	0.0022%
PJM-W	0.04	0.13	119	0%
PJM-S	4.58	11.48	20,215	0.0096%
PJM-E	0.11	0.22	125	<0.0001%
NYISO	0	0	0	0%
ISONE	0	0	0	0%

In results with some, but artificially limited interregional transfers (levels assumed by ISOs or firm imports)

- “Resource Adequacy Transmission [RA Tx]” case assumes interregional transfer capability based on assumptions used by the ISOs or firm imports in the NERC LTRA.
- On average some place in the Eastern Interconnect will have loss of load risk 8.5 days/year. But this risk is spread across many regions and rarely occurs simultaneously.
- PJM and SPP have high loss of load risk if interregional transfers are limited and new resources are not added.
- PJM’s loss of load risk is concentrated in the transmission constrained and high load growth PJM-S sub-region.
- MISO shows moderate resource adequacy risk, due to deficiencies in the MISO-C region, along with SERC-E.
- NYISO and SERC-C show risk only in cases without interregional transfer capability.
- SERC-FL, SERC-SE, and ISONE show limited or no resource adequacy risk

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Detailed Results

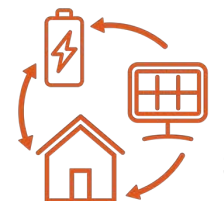
No Tx	LOLE days/yr	LOLH hrs/yr	EUE MWh/yr	NEUE % of load	RA Tx	LOLE days/yr	LOLH hrs/yr	EUE MWh/yr	NEUE % of load	Full Tx	LOLE days/yr	LOLH hrs/yr	EUE MWh/yr	NEUE % of load
Total EI	18.26	86.38	235,771	0.0070%	Total EI	9.40	33.39	64,642	0.0018%	Total EI	4.75	11.41	11,882	0.0004%
SPP	11.68	55.72	138,319	0.0415%	SPP	4.00	18.38	36,060	0.0108%	SPP	0.40	1.63	968	0.0003%
SPP-N	8.94	41.35	32,807	0.0395%	SPP-N	3.18	12.56	9,162	0.0111%	SPP-N	0.27	1.25	462	0.0006%
SPP-S	10.82	49.38	105,512	0.0422%	SPP-S	3.61	15.59	26,899	0.0107%	SPP-S	0.18	0.56	506	0.0002%
MISO	3.97	16.84	40,946	0.0055%	MISO	0.67	2.09	3,547	0.0005%	MISO	0	0	0	0%
MISO-W	1.22	4.77	4,342	0.0019%	MISO-W	0.07	0.16	155	0.0001%	MISO-W	0	0	0	0%
MISO-C	3.78	15.27	28,111	0.0141%	MISO-C	0.67	2.06	3,245	0.0016%	MISO-C	0	0	0	0%
MISO-E	2.80	11.14	8,323	0.0084%	MISO-E	0.05	0.19	101	0.0001%	MISO-E	0	0	0	0%
MISO-S	0.11	0.30	171	0.0001%	MISO-S	0.03	0.09	45	<0.0001%	MISO-S	0	0	0	0%
SERC-C	2.07	8.59	9,348	0.0038%	SERC-C	0.08	0.19	155	0.0001%	SERC-C	0	0	0	0%
SERC-E	2.64	7.63	8,001	0.0032%	SERC-E	1.73	4.49	4,381	0.0018%	SERC-E	0.00	0.00	1	<0.0001%
SERC-FL	0.08	0.11	57	<0.0001%	SERC-FL	0.06	0.07	39	0.0000%	SERC-FL	0	0	0	0%
SERC-SE	0	0	0	0%	SERC-SE	0	0	0	0.0000%	SERC-SE	0	0	0	0%
PJM	5.05	14.85	38,899	0.0042%	PJM	4.58	11.49	20,460	0.0022%	PJM	4.39	9.84	10,913	0.0012%
PJM-W	0.26	1.21	1,657	0.0004%	PJM-W	0.04	0.13	119	0%	PJM-W	0	0	0	0%
PJM-S	5.05	14.85	36,836	0.0174%	PJM-S	4.58	11.48	20,215	0.0096%	PJM-S	4.39	9.84	10,913	0.0053%
PJM-E	0.22	0.55	407	0.0002%	PJM-E	0.11	0.22	125	<0.0001%	PJM-E	0	0	0	0%
NYISO	0.21	0.43	194	0.0001%	NYISO	0	0	0	0%	NYISO	0	0	0	0%
ISONE	0.01	0.02	5	<0.0001%	ISONE	0	0	0	0%	ISONE	0	0	0	0%

Loss of Load Expectation by Month



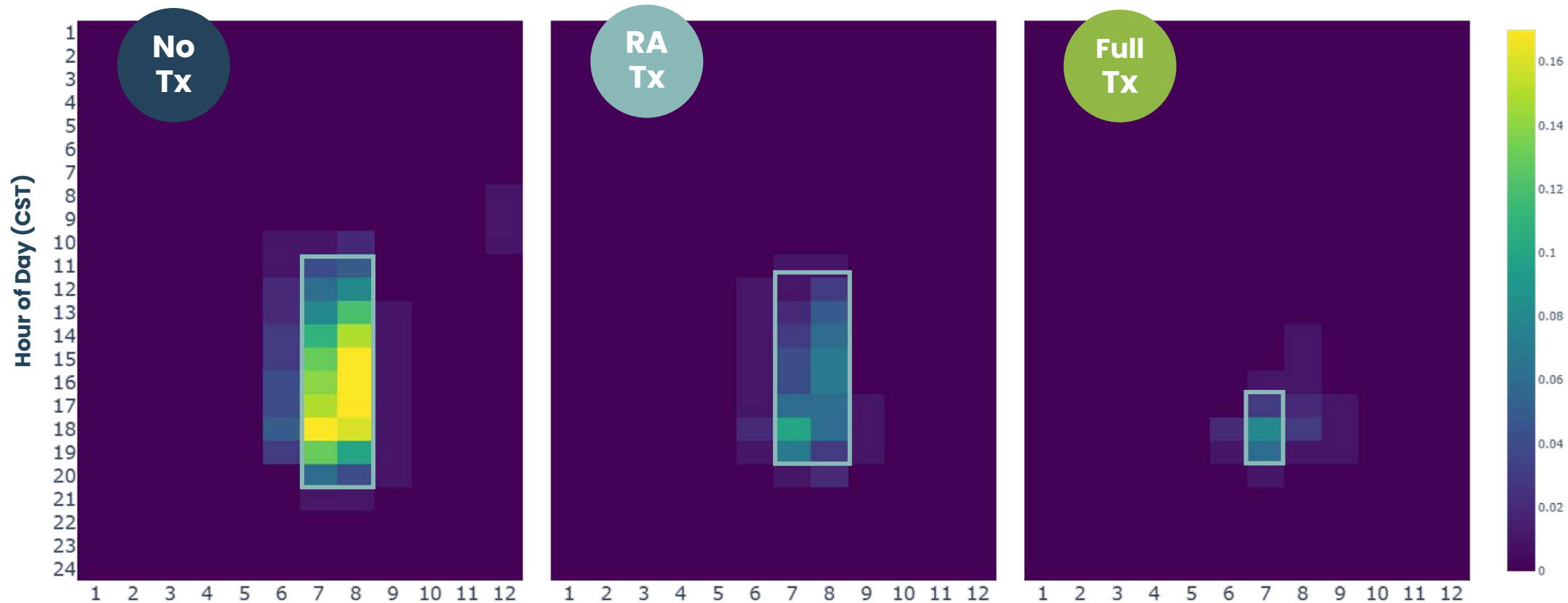
- For the wide area assessment, a loss of load event occurs if there is unserved energy anywhere in the Eastern Interconnect
- One region with one loss of load hour on a day, counts as an unserved energy event for the entire EI.
- Loss of load expectation concentrated in peak summer demand months
- Limited/no unserved energy in winter demand periods because correlated outages and fuel supply disruptions are not included at this point.

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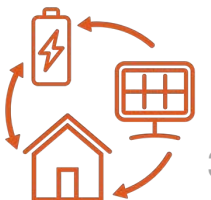
Heatmap of loss of load risk

Loss of load probability by month and hour, % of all hours

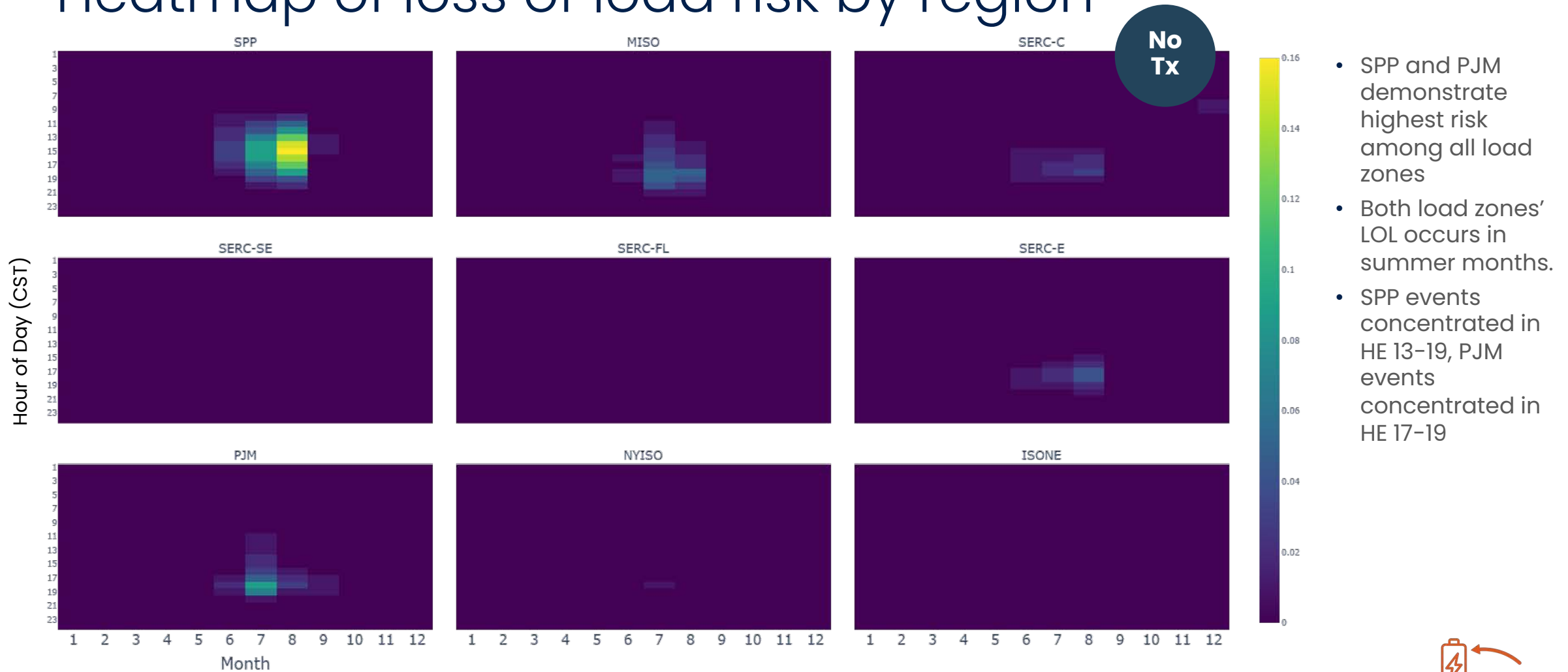


- Loss of load risk window occurs in summer evenings, primarily HE 14–20, July and August
- Interregional transmission shortens risk window, further enabling storage resources for RA

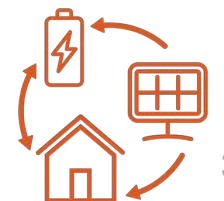
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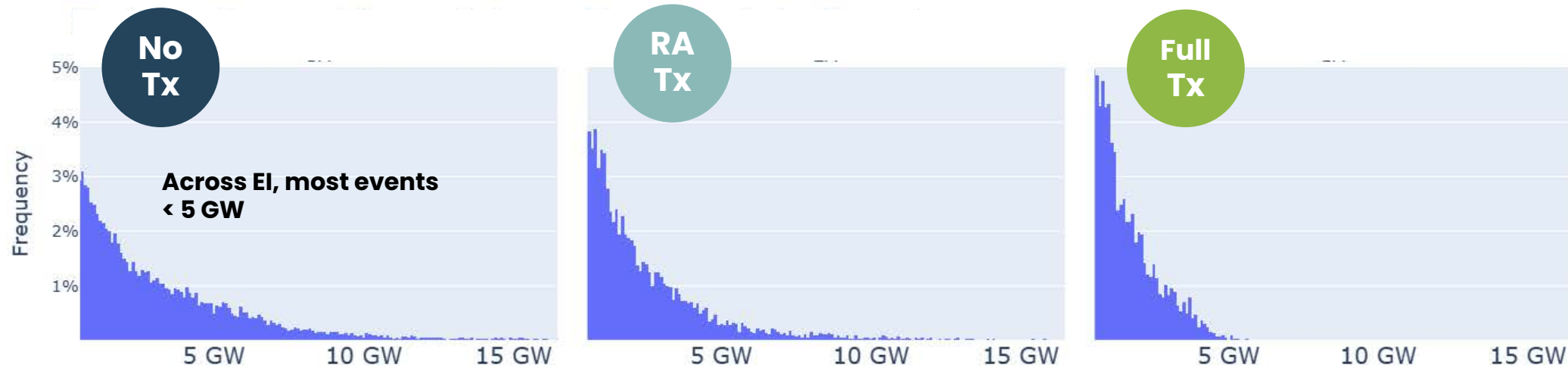
Heatmap of loss of load risk by region



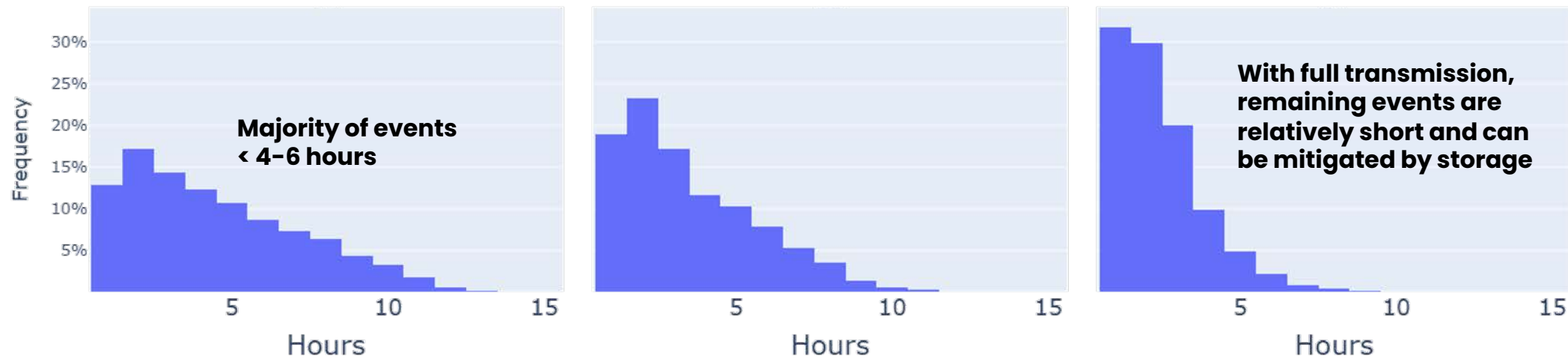
RETHINKING RELIABILITY



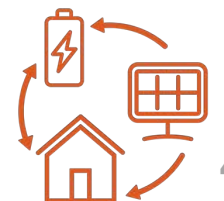
Event Histograms – Max Unserved Energy



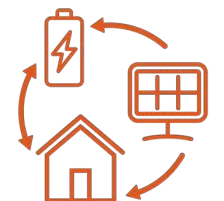
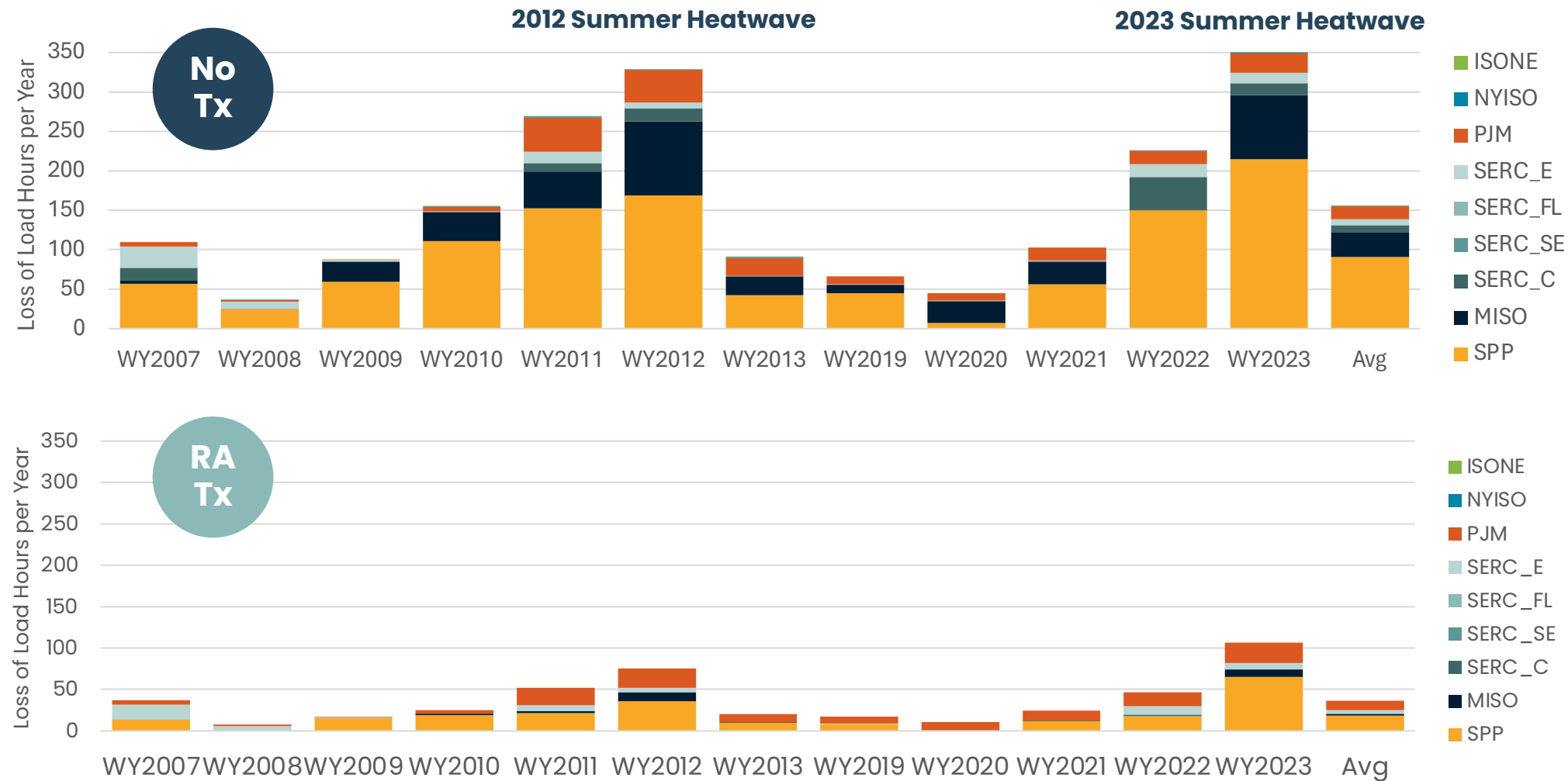
Event Histograms – Duration (Hours)



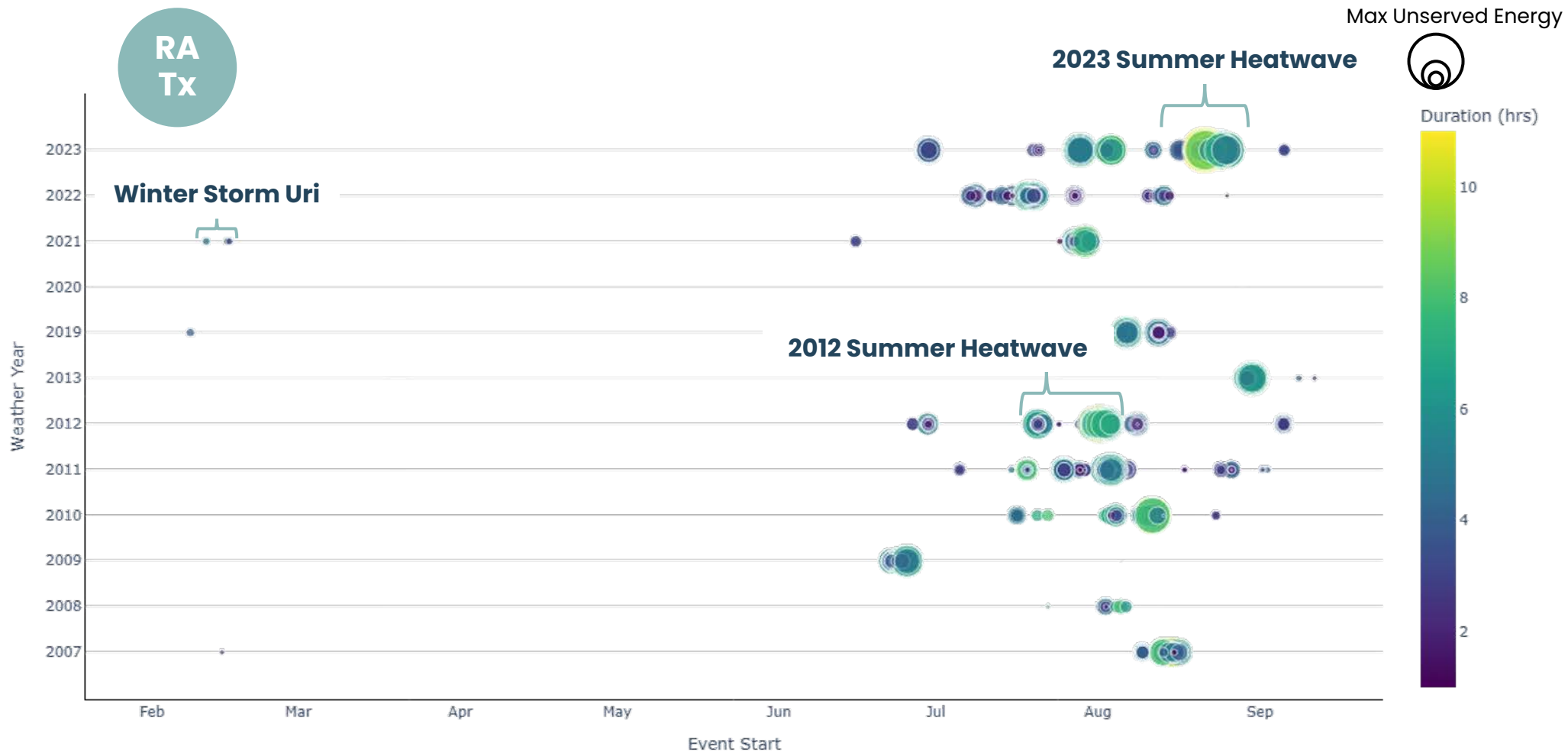
RETHINKING RELIABILITY



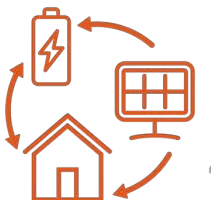
Regional LOL Hours – By Weather Year



Event Duration and Magnitude Timelines



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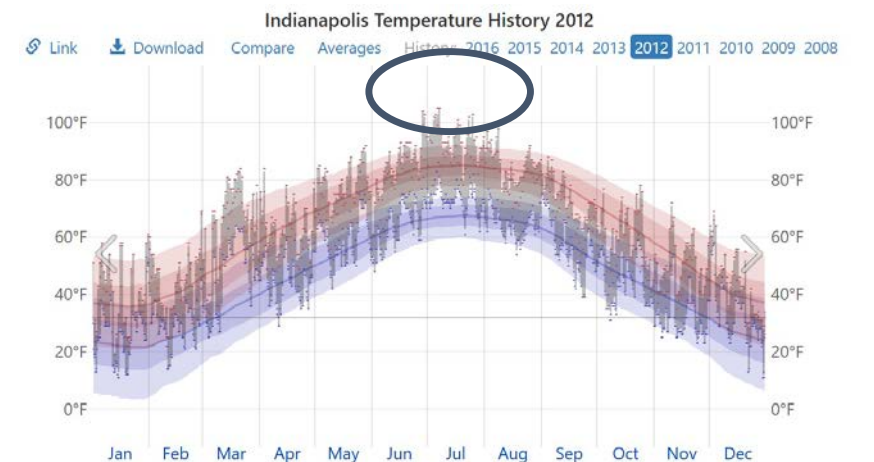
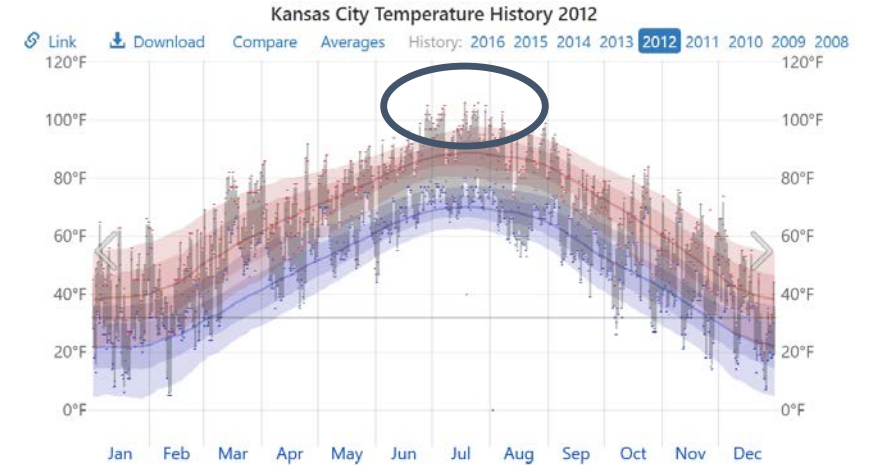


Extreme Temperature Assessment

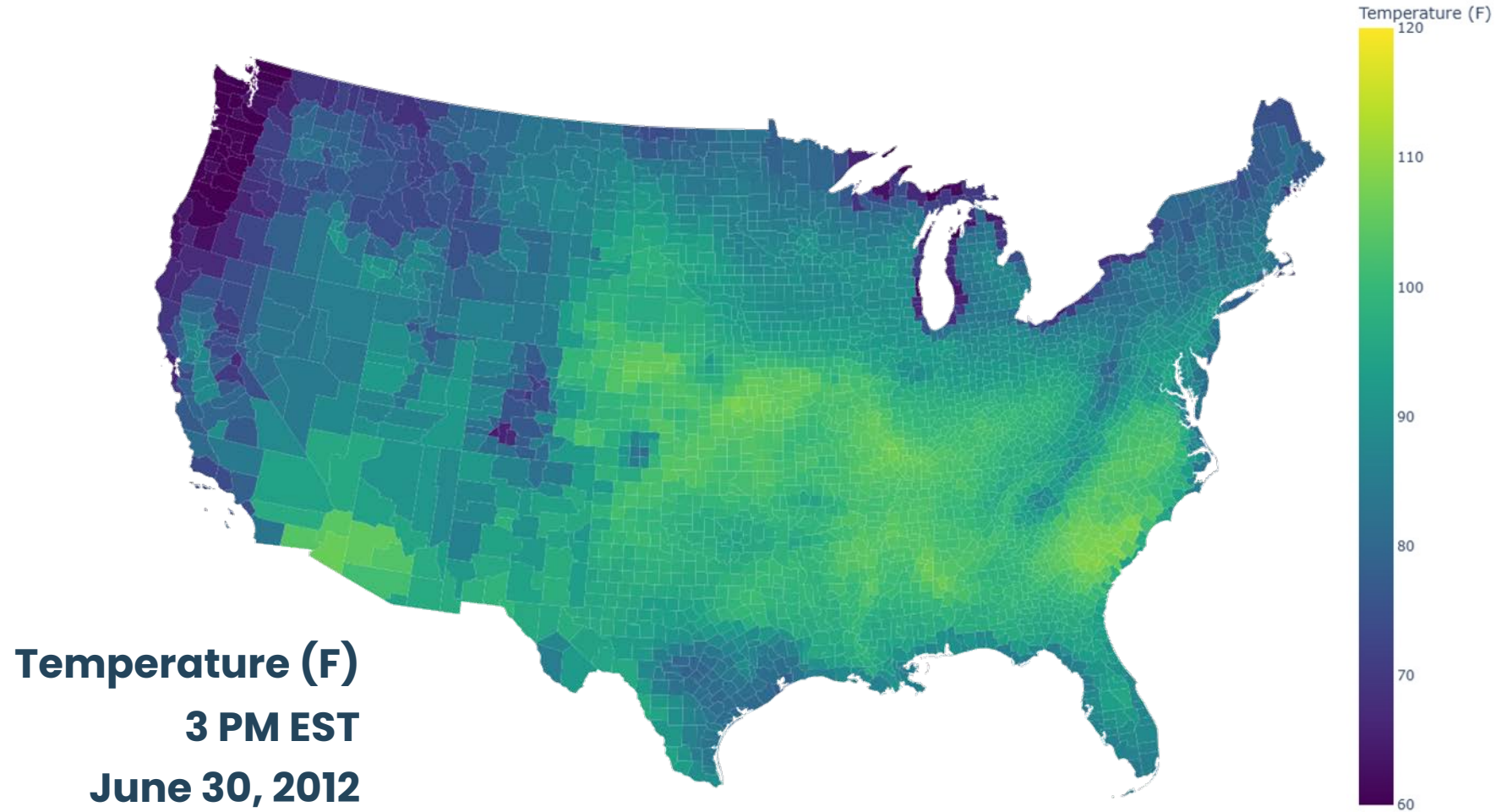
Hottest wide-area heat events on record, 1980–2022

Event Type	Start Date	End Date	SPP	MISO	SERC	Florida	PJM	New York	New England
Heat Event	6/24/1980	7/2/1980							
Heat Event	8/23/1984	8/29/1984							
Heat Event	7/3/1988	7/20/1988		6	15		7		
Heat Event	7/22/1988	8/8/1988		3			15		22
Heat Event	8/11/1988	8/19/1988		1			5	7	18
Heat Event	6/23/1990	6/29/1990							
Heat Event	7/16/1991	7/24/1991					16	9	1
Heat Event	7/25/1995	7/31/1995							
Heat Event	6/15/1998	6/21/1998				1			
Heat Event	6/29/1998	7/5/1998				2			
Heat Event	7/9/1998	7/22/1998							
Heat Event	7/2/1999	7/8/1999					3	1	6
Heat Event	8/31/2000	9/7/2000							
Heat Event	8/5/2001	8/12/2001					8	3	5
Heat Event	6/23/2002	7/6/2002					18	13	2
Heat Event	7/8/2002	7/16/2002							
Heat Event	7/2/2003	7/17/2003							13
Heat Event	7/9/2005	7/24/2005							
Heat Event	7/13/2006	7/27/2006							
Heat Event	7/27/2006	8/5/2006	7	4			5	4	4
Heat Event	8/6/2007	8/19/2007			2				
Heat Event	8/28/2010	9/5/2010							10
Heat Event	7/16/2011	7/25/2011	9				6	2	3
Heat Event	7/30/2011	8/6/2011	2		4				
Heat Event	6/17/2012	7/9/2012	5	2	1		1		
Heat Event	7/29/2012	8/5/2012	1	8					
Heat Event	6/24/2018	7/10/2018						16	

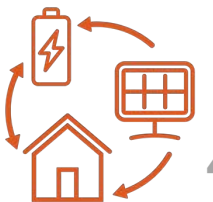
June, July 2012 held some of the hottest weather events in SPP, MISO, SERC since 1980



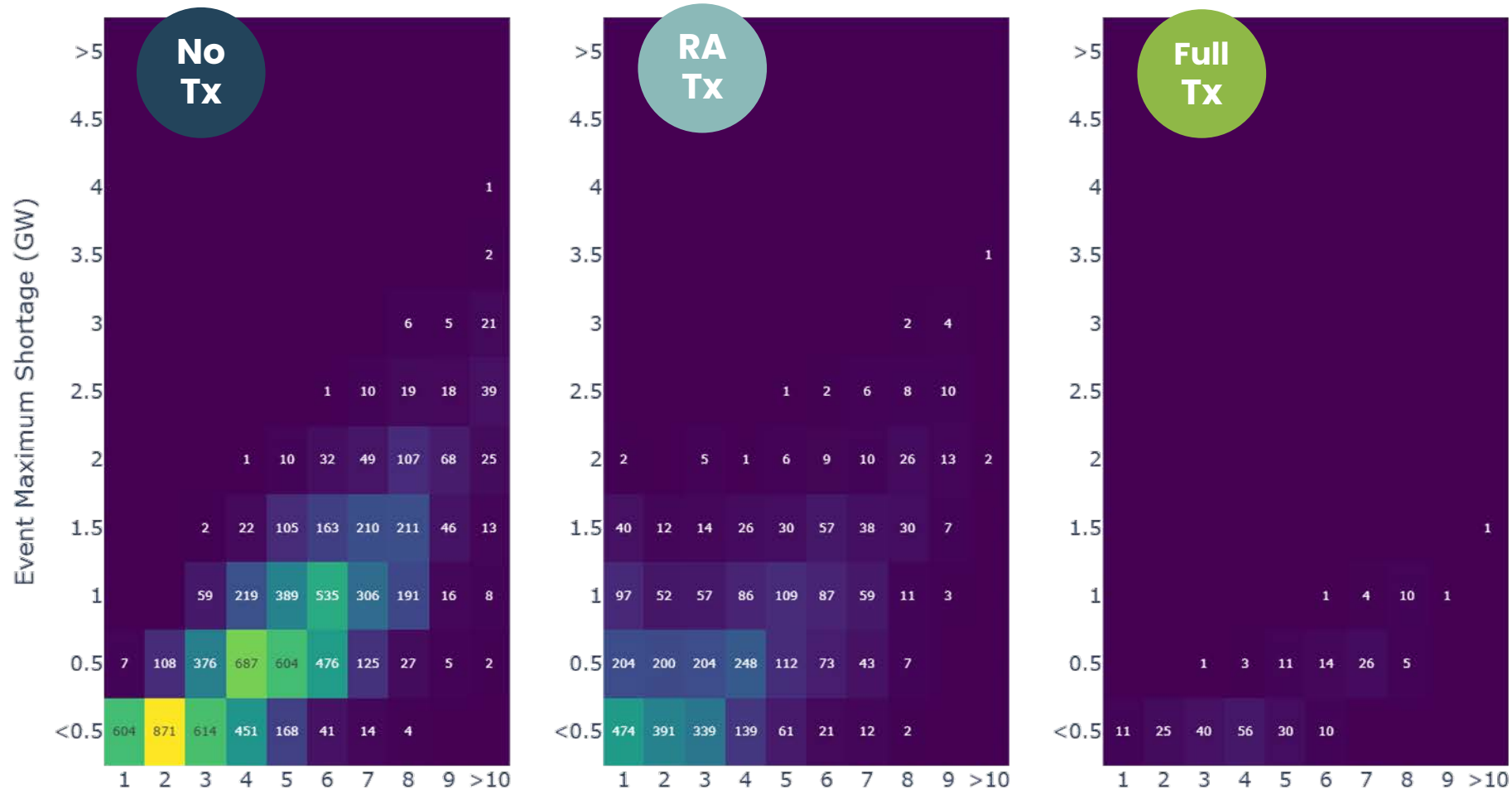
Map of 2012 Heat Event



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PJM-S Deep Dive: Event Statistics



As interregional transmission increases (left to right), duration and maximum energy shortage decrease

PJM-S Sensitivity Analysis

Three sensitivities to address PJM-S risk

A. Capacity Additions

- +4 GW Battery Storage (33% of Queue)
- +1 GW of OSW (40% of Queue)
- +3 GW of Solar (25% of Queue)

B. Import TX Additions

- 4 GW increase to PJM-S Total Import Limit, but still below the non-coincident transfer capability of individual interfaces [9,580 MW → 13,580 MW]

C. Half of Capacity and Import TX Values

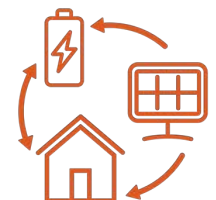
Significant decrease in loss of load risk

PJM-S	LOLE days/yr	LOLH hrs/yr	EUE MWh/yr
Base Case [No Tx]	5.05	14.85	36,836
A. Resources	0.05	0.06	25
B. Transmission	0.12	0.14	107
C. Resources + Tx	0.06	0.07	40

**based on 300 samples instead of 900*

PJM-S can meet its resource adequacy needs with either new clean energy resources or new transmission using less than a third of the proposed interconnection queue resources and no new gas.

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Key Findings and Future Research

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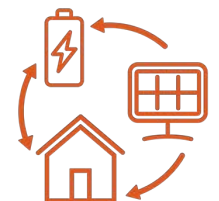


Key Findings

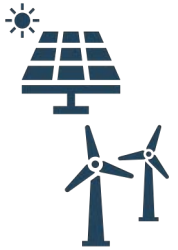
In 2028, with assumed load growth, generator retirements, and limited new resources:

- Most regions in EI have moderate to high loss of load risk if interregional transfers are not included. SERC-SE, SERC-FL, ISONE have sufficient resources to meet load without imports.
- Regional diversity in load, wind and solar generation, and loss of load risk shows that capacity can be transferred between regions, even when each region in isolation is inadequate.
- With interregional transfer levels assumed by the regions (RA Tx) most regions have sufficient resources when regions are evaluated together.
- PJM and SPP show high LOLE risk without new additions, even when allowing imports from neighbors. PJM-S is import constrained, leading to high RA risk even with surplus capacity in PJM-E and PJM-W.
- Remaining resource adequacy risk can be mitigated with a portfolio of clean energy (including demand response , given durations of the events) or interregional transmission resources

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Future Research and Data Improvements



Future Clean Energy Portfolios

While this study evaluated announced retirements and additions of wind, solar, and storage deployment, future studies that evaluate higher levels of retirements and new resource additions can quantify resource needs.



Additional Load Years

This study used 12-years of consistent and correlated weather data for wind, solar, and load. Additional study years, notably for load, would increase statistical power.



Weather Dependent Outage Rates

Additional data on thermal resource reliability, including cold weather forced outages and fuel supply constraints, is required. Sector coupling between the natural gas system and power system is also necessary.



Increased Transmission Scenarios

In tandem with generation scenarios, increased inter- and intra-regional transmission can address regional energy shortfalls.



Transmission Accreditation

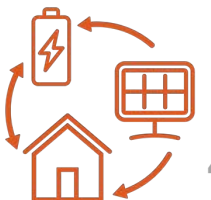
Wide area assessments can be used to calculate capacity contributions for new interregional transmission, compare accreditation to resource options and prioritize new development.



Weather and Climate Data

Power system reliability is becoming increasingly driven by the weather. Improved data for correlated wind, solar, load, and temperature is needed, with and without climate change trends.

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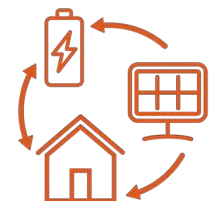
Improvements for Additional Use Cases

The wide-area assessment conducted for this study can be expanded for other use cases:

- **ISO Long-Term Planning and Future Grid Studies:** ISOs can utilize this dataset for long-term planning studies or analyses to evaluate capacity benefits of ties and market assistance. In this case, the dataset should update generator capacities and load forecast to latest ISO forecasts. In addition, resource aggregation for the individual ISO can be adjusted where necessary and can incorporate unit-specific modeling if desired. Internal transfer capability can also be adjusted to align with ISO capacity zones.
- **Utility IRPs:** The dataset can be used to evaluate individual IRPs, either to support PRM and ELCC studies or to perform a post-hoc, “reliability-back-check” on the resulting IRP portfolios. For this use case, the utility will need to disaggregate the region into individual balancing authorities, and replace generator capacities, aggregations, and load forecast with utility-specific plans.
- **Transmission Accreditation Studies:** The dataset can be used to accredit the capacity contributions of interregional transmission. To do this both regions should be brought to the reliability criterion (i.e. 0.1 days/year) and then new transmission can be added between the regions to measure incremental capacity contributions.

Please consult the [GridPath EI GitHub repository](#) and reach out to the GridLab and Telos Energy with any questions related to follow-on work

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Thank you!

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